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PETROLEUM DEVELOPMENT AND TECHNOLOGY

1947

PETROLEUM DIVISION

A. I. M. E.

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TRANSACTIONS

OF THE

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(INCORPORATED)

Volume 170

American Institute of Mining, Metallurgical, and Petroleum Engineers, //

PETROLEUM DEVELOPMENT AND TECHNOLOGY

1947

PETROLEUM DIVISION

PAPERS AND DISCUSSIONS PRESENTED BEFORE THE DIVISION AT MEETINGS HELD AT
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FOREWORD

This volume of Petroleum Development and Technology is a permanent record of a part of the activities of the Petroleum Division and gives evidence that the year 1946 was a very successful one for the Division. In most cases the papers included in this volume were prepared for presentation at the Annual Meeting of the Institute held at Chicago in February and at the two fall meetings of the Division held at Galveston and Los Angeles in October.

These Transactions include papers on petroleum research, production and economics, along with recorded discussion. In addition, a review of Refinery Engineering for 1946 is included. Although the Committee on Refinery Engineering no longer exists in the Division it is to be hoped that Mr. Walter Miller will continue this valuable service which he has contributed for the past 15 years. Much progress in petroleum technology and good hard work are represented by these papers and the authors are to be commended for their participation in the Division's activities. For the second consecutive year statistics of oil and gas development and production have been published in a separate volume. This volume of statistics is available to all members of the Institute, upon request and without cost, who have selected to receive either Petroleum Technology or this Transactions volume.

At the Seventy-fifth Anniversary Celebration of the Institute held in New York City during March 1947, Dr. William N. Lacey was awarded the Anthony F. Lucas medal. His photograph and citation for award appear in this volume.

To the members of all Petroleum Division committees for 1946 much credit is due for the success and progress of the Division throughout the year. Special recognition is given to Messrs. H. F. Beardmore, Chairman, and William H. Strang, Executive Secretary of the Division, for their enthusiasm and hard work in the interests of the Division and its many members.

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In 1936 the Institute established the Anthony F. Lucas Gold Medal, to be awarded from time to time "for distinguished achievement in improving the technique and practice of finding and producing petroleum." These awards are sponsored by the Petroleum Division.

Captain Lucas was a pioneer in the oil industry, one of the early wildcatters and a leading mining and petroleum engineer. He was famous as the discoverer of Spindletop. He became a member of the Institute in 1895 and in 1913 was the first Chairman of the Petroleum and Gas Committee of the Institute, the forerunner of the present Petroleum Division. He also headed the Committee in 1914, 1917 and 1918.

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"For his distinguished achievement in directing research work in the fundamentals of hydrocarbon behavior and particularly his application of these fundamentals to oil and gas reservoirs which have led to greater efficiency in oil and gas production from our oil fields. His published data have been of immense value to the petroleum industry in determining improved producing procedures for the various types of oil and gas reservoirs."

A New Method for Measurement of Oil Saturation in Cores

R. L. Boyer,* F. Morgan* and M. Muskat,* Member AIME

(Galveston Meeting, October 1946)

Abstract

This paper describes a new method for measuring the oil saturation of cores during the course of fluid-flow experimentation. The method depends upon the addition to the oil of a soluble tracer material that is the primary absorber of the X-rays incident upon the core. The paper includes a description of the X-ray equipment and intensity-measuring apparatus, calibration data for two cores, and results obtained with additional cores for various conditions of oil and water-flooding. The data and results are presented to show the potentialities of the X-ray method at this stage of development rather than to establish particular concepts pertaining to fluid-displacement mechanisms of permeable media. Further development of this method will include adequate pressure and flow-rate control in the liquid and gas-flow systems, as well as additional stabilization of the X-ray power supply.

Introduction

In the last several years a type of application of the fundamental permeability-saturation relationships has been developed which offers great promise in the interpretation of general reservoir performance.[1-4] In these developments no attempt is made to solve the detailed flow dynamics in actual oil and gas-producing systems. That problem still remains unsolved. But the permeability-saturation phenomena are incorporated in the analysis of oil-producing reservoirs in a manner such as to reflect the true role they play in controlling the gross reservoir behavior. In particular, they are introduced in such a manner as to determine the gas-oil ratio of the production at any stage of depletion, and, when combined explicitly with the so-called material-balance principles in differential form, one can obtain a differential equation describing completely the average pressure and gas-oil-ratio history of oil-producing reservoirs. While thus far they have been applied directly only to gas-drive reservoirs, they are susceptible of extension to partial water-drive systems, and qualitatively the same principles are of value in the study of complete water-drive reservoirs. Moreover, in addition to giving a means for computing the variation of the reservoir pressure and gas-oil ratios vs. the cumulative production, they automatically lead to predictions of the gross ultimate recovery under natural depletion—and when properly extended they provide means for predicting the ultimate recovery under gas or water injection.

The data required for such applications are the initial fluid distribution in the producing section, the pressure-volume-temperature data on the gas and liquid phases, and the permeability-saturation relationship for the oil-saturated zone. The former can be obtained with reasonable accuracy by methods that are well established and available throughout the industry. The permeability-saturation data, however, involve techniques that are not at all standardized. In fact, only

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Manuscript received at the office of the Institute Aug. 2, 1946. Issued as TP 2124 in Petroleum Technology, January 1947.

* Gulf Research and Development Co., Pittsburgh, Pennsylvania.

[1] References are at the end of the article.

one method that is applicable to cores of the size commonly available by standard coring procedures has been described in the literature.[5] For routine measurements this method apparently is being used only for two-phase flow systems, although in its original development it appeared to offer promise for extension to three-phase fluid mixtures.

Without specific data on the permeability-saturation characteristics of the particular producing rock in question, no quantitative significance can be given to the calculations regarding the reservoir performance. From such measurements as have been made, it appears that there may be enough variation in these relationships between different kinds of producing rock to materially affect the performance from different reservoir strata, and, in particular, the ultimate recoveries. Accordingly, it is of the utmost importance that a generally available, reliable and rapid method be developed that will permit the determination of the permeability-saturation curves on typical oil-field cores.

Perhaps the outstanding problem to be solved in developing a new method for these measurements is the provision of means for determining the liquid saturation within the core during the course of the flow measurements. In principle, it can be done by removing the core from its holder and weighing it but this will give only an average saturation at the best. Moreover, in the course of removal of the core from its holder and subsequent manipulation the fluid distribution may change, and there will be an uncertainty regarding the actual distribution pertaining to the permeability measurement. While the determination of the permeabilities to the individual phases involves also problems of technique not yet completely solved, a rapid method for measuring the oil saturation in situ appears to be the first major step required in the solution of the problem as a whole. It was for the purpose of developing such a method that the research study reported herein was undertaken.

The basic principle underlying the method to be described here lies in the measurement of the absorption of X-rays by the core and its fluid content.* X-rays are generally considered to be a highly penetrating form of radiation, and indeed, they are transmitted through most materials of low density such as rocks, water, and oil, with little attenuation. Using the ordinary fluids encountered in oil production, they would produce such low degrees of absorption in the X-ray beam that it would be difficult to interpret the measurements in terms of the fluid saturation. Moreover, it would be almost impossible to discriminate between the adsorption due to the water and oil phases. If, however, one adds to the oil phase a component having a high absorption coefficient, the absorption due to this additive may be considered as proportional to the amount of the total oil saturation present. In this sense, the additive may be termed an X-ray tracer. Actually, however, it has been found that a relatively high concentration of the tracer is necessary, so that the use of the term may be questionable in the sense that it really does not represent simply an impurity in the oil phase. On the other hand, the type of tracer used, iodobenzene, appears to make little change in the general physical properties of the oil,† and there is no reason to fear that the experimental results will be affected thereby; in fact, for some purposes, it may be desirable to use the tracer itself as an equivalent of the oil phase. As independent evidence, however, has shown that the absolute values of the viscosity and the surface tension are of minor importance in determining the permeability-saturation relationship, the use of large concentrations of iodobenzene is felt to be perfectly trustworthy.

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* The application of the principle, including the use of absorbing "tracers," and the early experiments establishing its possibilities, are the contribution of W. L. Kehl, of this laboratory.

† In fact, the surface tension of the 25 pct iodobenzene solution used in the present study was 32.5 dynes per cm, and the interfacial tension with water was measured as 29 dynes per cm at 70°F. These values are both comparable to those for natural crude-oil systems.

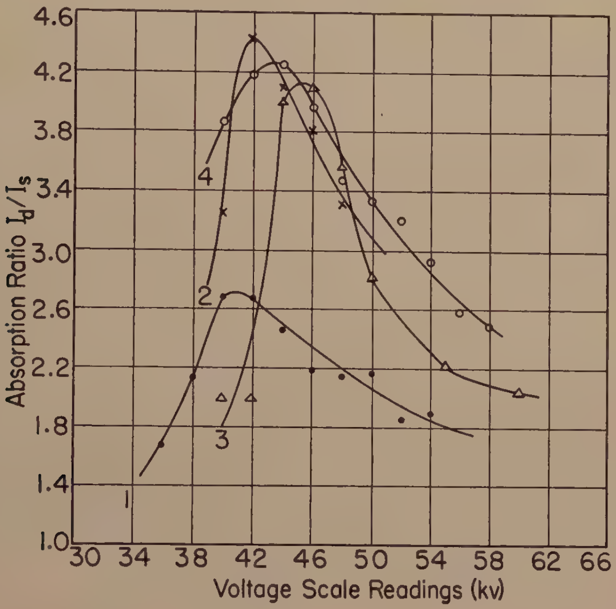

FIG 1—ABSORPTION CURVES FOR X-RAY BEAM USING VARIOUS FILTERS.
I_d = intensity through dry core.
I_s = intensity through oil and tracer saturated core.
I, no filter; 2, ¼-mm copper; 3, ¾-mm copper; 4, 2-mm aluminum.

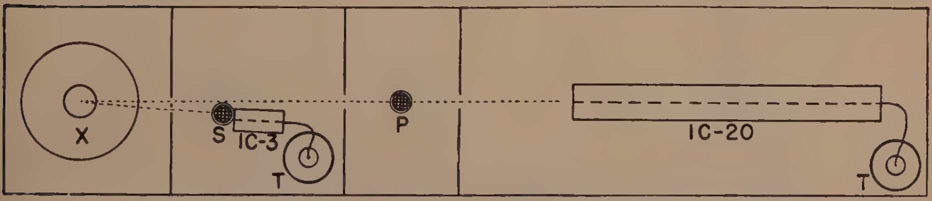

FIG 2—SCHEMATIC LAYOUT OF X-RAY TUBE AND IONIZATION CHAMBERS.
X, X-ray tube.
P, test core.
S, saturated core or equivalent absorber.
IC-20, ionization chamber for X-ray beam through test core.
IC-3, ionization chamber for X-ray beam through saturated core.
T, FP-54 amplifier tube and metal shield.

While the major purpose of the study reported here has been the development of a means of measuring oil saturation in place to facilitate the determination of permeability-saturation curves, it may be observed that the technique so developed has a much wider range of applicability. In particular, it provides means for studying the detailed dynamics of fluid motion within a porous medium; that is, the progress of displacement of oil by gas or water, or the converse, can be followed in detail by scanning with the X-ray beam the fluid distribution along the length of the core in which these phenomena are taking place. Problems of fluid redistribution under the action of gravity can also be studied in this manner. Except for the method of neutron scattering recently described by Brunner and Mardock,[6] there has been heretofore no technique available for the detailed investigation of this type of problem, yet it is of extreme importance for the complete understanding of the detailed mechanics of oil production. A few examples of this kind of application will be given in this report, although they are not to be construed as comprising a complete study of this phase of the subject.

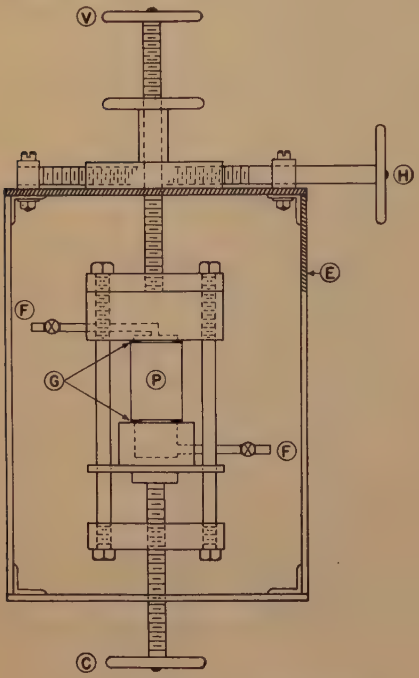

Fig 3—Shielded core holder.
C, core-clamping screw.
E, lead enclosure.
F, gas-liquid flow connections.
G, rubber gaskets.
H, horizontal adjusting screw.
V, vertical adjusting screw.
P, test core.

X-ray Equipment and Intensity-measuring Apparatus

The X-ray tube and power supply are of conventional industrial type, with tungsten target operating at voltages less than 60 kv. In oil-saturation measurements an optimum operating voltage was determined experimentally by adjusting the tube voltage to obtain a maximum in intensity ratio for the X-ray beam transmitted by a dry core and by a core saturated with the oil containing the tracer material. Curves showing such intensity ratios with various absorbers interposed in the beam are plotted in Fig 1. The abscissa scale in Fig 1 refers to meter readings that are only approximately the true voltage applied to the X-ray tube. This optimum operating voltage minimizes the effect of fluctuations in the power input to the X-ray tube; these power fluctuations limit the accuracy and reproducibility of the saturation measurements.

A schematic layout of the X-ray tube, the plastic-mounted core, and ionization chambers is shown in Fig 2. The core is supported in a core holder adjustable to various positions in directions normal to the path of the X-ray beam. A sketch of the core holder with its connections for liquid flow and gas flow is shown in Fig 3. Two ionization chambers (IC-20 and IC-3) were used in all the measurements described in this paper. The second ionization chamber (IC-3) with its absorber[*] is used as a measure of the output of the X-ray tube. The ratio of the current in ionization chamber IC-20 to that in IC-3 is used as a measure of the intensity of the X-ray beams passing through the core of unknown oil saturation. This ratio provides an approximate correction of the intensity measurement for changes in the X-ray beam emitted from the tube target.

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[*] In preliminary experiments this absorber was a Bakelite-mounted core of Nichols buff sandstone completely saturated with oil and sealed with cellulose tape. However, for the calibration data and subsequent flow experiments described in the following pages, the saturated core was replaced by iron filters, which showed approximately equivalent X-ray absorption at the optimum operating voltage of the X-ray tube.

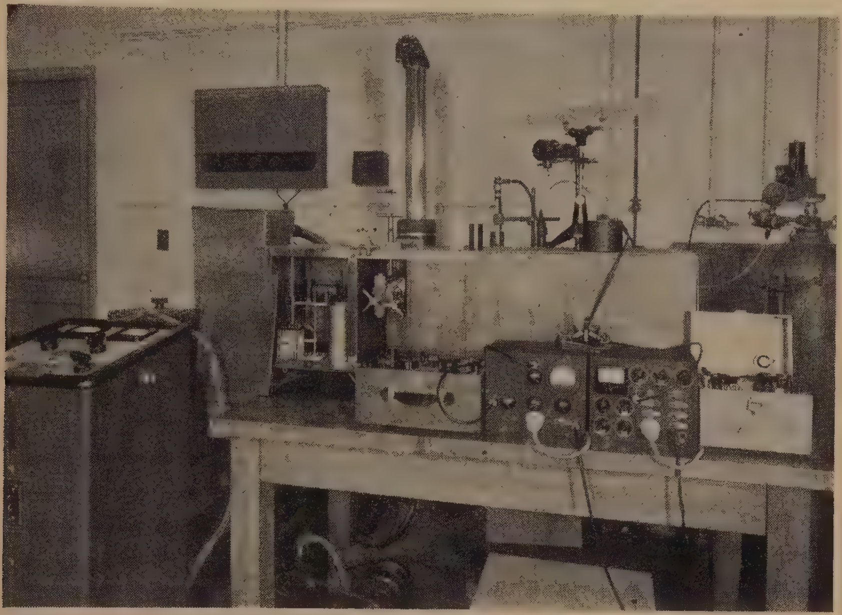

FIG 4—EXPERIMENTAL APPARATUS.

A photograph of the composite experimental arrangement is shown in Fig 4.

The ionization chamber IC-20 consists of a brass tube 2¼ in. in diameter and 20 in. long fitted with plexiglass windows at the ends; a brass-rod electrode is supported by holes in the centers of these windows. The potential difference between the electrode and the wall is 45 volts. The second ionization chamber, IC-3, is of similar design, except that it is 1½ in. in diameter and 3 in. long.

The collector electrode of the ionization chamber IC-20 is connected to the control grid of an FP-54 Pliotron tube in an amplifier circuit. The circuit diagram is shown in Fig 5. The amount of ionization produced by the X-ray beam in the ionization chamber is measured by the change of voltage of the control grid. This voltage change is conveniently measured by the use of a potentiometer in the control-grid circuit to restore the galvanometer to zero reading when X-rays produce ionization in the ionization chamber. This potentiometer reading measures the intensity of the X-ray beam in IC-20, after passing through the core of unknown oil saturation.

The collector electrode of the ionization chamber IC-3 is connected to a similar amplifier and potentiometer circuit. The potentiometer reading obtained for the X-ray ionization in IC-3 is a measure of the output of the X-ray tube.

A calibration curve is obtained by measuring the values of X-ray intensity of a core at several values of oil saturation between 0 and 100 pct, determined by weighing the core at each saturation. Such data are presented and discussed in the next section.

Calibration Curves for Oil Saturation of Cores P-10 and B-1

As indicated in the introduction, iodobenzene was used as the X-ray absorbing tracer. Accordingly, the "oil" referred to in the following really was a 25 pct concentration solution of iodobenzene and mineral seal oil, except when indicated otherwise.

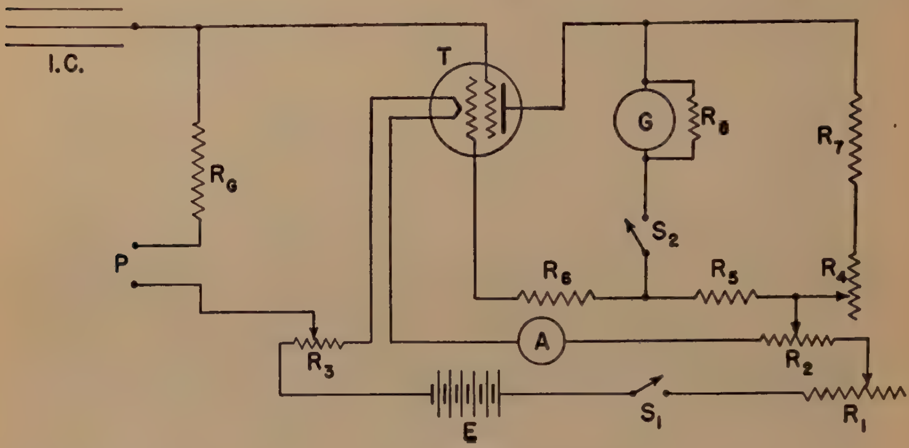

FIG 5—AMPLIFIER CIRCUIT DIAGRAM.

IC, ionization chamber.
A, milliammeter.
E, storage battery.
P, 0-1 volt potentiometer.
G, galvanometer.
S_1, S_2, switches.
T, FP-54 tube.
R_g, grid resistance.
R_1—R_8, resistances and potentiometers.

In the calibration experiments the X-ray intensity was measured with the core in the core holder at ¼-in. intervals along its length. The average of these readings was used as the X-ray intensity value for the oil saturation of the core. The weight per cent oil saturation was obtained by weighing the core on an analytical balance and calculating the oil content from its original dry weight, the porosity of the core, and oil density; namely, 1.05.

To obtain further information about the X-ray absorption characteristics of iodobenzene a number of X-ray intensity measurements were made with 2-mm and 4-mm (liquid path) absorption cells and various absorbers in the X-ray beam. The results are shown graphically in Fig 6. The curve for iodobenzene in the 4-mm absorption cell with a dry core as absorber indicates that the absorption coefficient is not constant but decreases as the concentration of iodobenzene in the mineral seal oil increases.* The other curves show the effect of using flat metal absorbers instead of a dry core, together with the effect of a slight change in the operating voltage of the X-ray tube.

Another series of measurements was made for the saturation and desaturation of a core with 100 per cent iodobenzene—that is, without dilution in mineral seal oil. These values were reproducible at oil saturations between 20 and 70 per cent with deviations no greater than 3 per cent, as shown in Fig 7. No deviations at low oil saturations from the general trend were observed when using 100 pct iodobenzene.

The use of a mixture of iodobenzene in mineral seal oil depends upon the extent of the selective separation of the iodobenzene from the mineral seal oil at low oil saturations. To determine whether this effect would be significant in the use of a core for an extended series of saturation measurements with gas-liquid flow two cores were prepared for calibration measurements. Core P-10 was a Nichols buff sandstone core, 7.68 cm long, 2.72 cm in diameter and 19.6 pct porosity. Core B-1 was a Berea sandstone core 7.64 cm long, 2.73 cm in diameter and 18.9 pct porosity.

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* This effect results from the change in spectral characteristics of the heterogeneous X-ray beam as it passes through increasing thicknesses of absorbing material—that is, increasing numbers of iodine atoms.

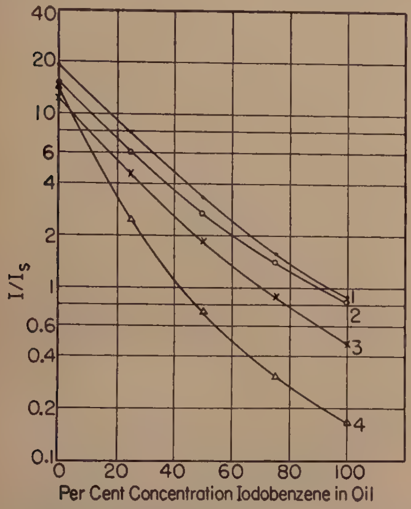

FIG 6—ABSORPTION CURVES FOR VARIOUS ABSORBERS AS FUNCTIONS OF CONCENTRATION OF IODOBENZENE.

$$I/I_s = \frac{\text{Intensity through absorber}}{\text{Intensity through saturated core}}.$$

1, 2-mm cell, copper absorber, tin filter, 47 kv.
2, 2-mm cell, dry core B-2, 43 kv.
3, 2-mm cell, copper absorber, 43 kv.
4, 4-mm cell, dry core, 43 kv.

Measurements of X-ray intensity and corresponding weight saturations of the cores were made during numerous saturation-desaturation experiments extending over a period of eight days. The calibration data for core P-10 are listed in Table 1 and plotted in Fig 8. The data for core B-1 are listed in Table 2 and plotted in Fig 9. The observed X-ray intensity values given in these tables actually are averages of the intensity readings taken at ¼-in. intervals along the core. Typical measurements from which the average X-ray intensity values were calculated are shown in Tables 3 and 4. The last columns in Tables 1 and 2 show the saturation range in the core at each average saturation value. These are the maximum and minimum values of saturation (corresponding to the X-ray intensity values) in the series of readings from which the average X-ray intensity was calculated. It will be observed from Figs 8 and 9 that the points for saturations less than 30 pct fall above the curves, probably because of selective separation of the iodobenzene resulting from the large quantities of gas throughput required to reduce the oil saturation to such low values. For the range of oil saturation of practical content this effect should be negligible.

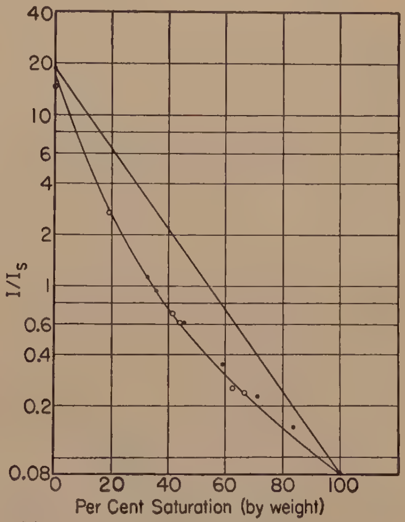

FIG 7—CALIBRATION CURVE FOR CORE P-10 USING 100 PER CENT IODOBENZENE.

$$I/I_s = \frac{\text{Intensity through core P-10}}{\text{Intensity through saturated (25 pct conc.) core}}$$

Black dot, data taken between 11/28/45 and 11/30/45; open circle, data taken between 12/3/45 and 12/10/45; straight line, expected relation for monochromatic X-ray beam.

The results obtained in calibration of cores P-10 and B-1 were used with other cores of similar composition for experiments on gas-driving and water and oil-flooding. Some experiments of this type are described in the latter part of this paper. The saturation data for these additional cores indicate that the absorption ratio—the ratio of I/I_f at 100 pct saturation to I/I_f at zero saturation—remains approximately constant for a particular core but varies slightly with different cores.

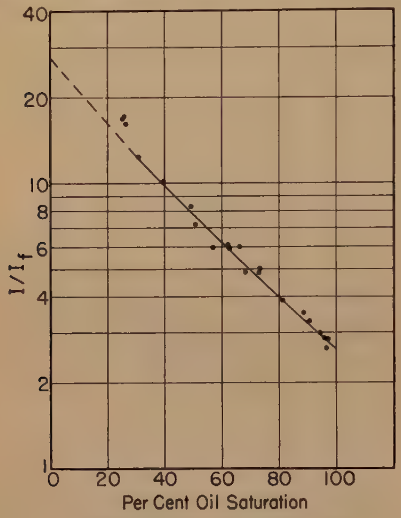

FIG 8—CALIBRATION DATA FOR CORE P-10.

$$I/I_f = \frac{\text{Intensity through P-10}}{\text{Intensity through filter}}$$

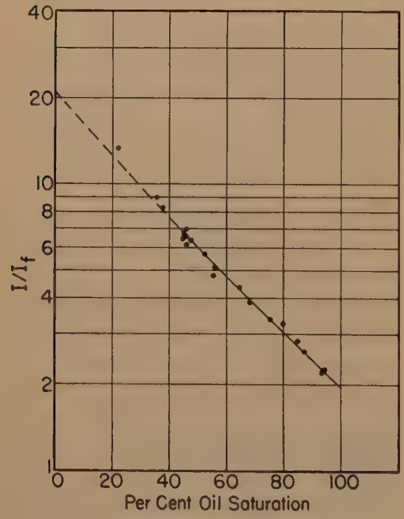

FIG 9—CALIBRATION DATA FOR CORE B-1.

$$I/I_f = \frac{\text{Intensity through B-1}}{\text{Intensity through filter}}$$

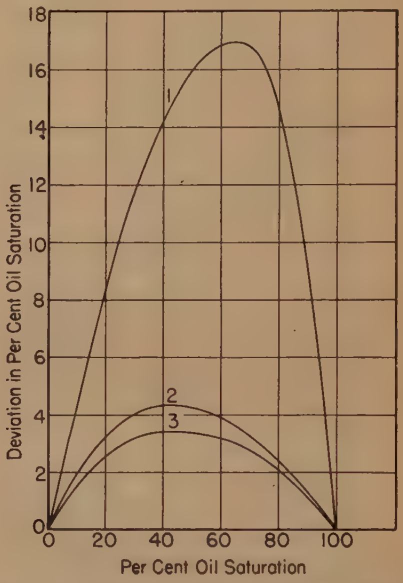

FIG 10—DEVIATIONS FROM SEMILOGARITHMIC LINEARITY OF CALIBRATION CURVES WITH DIFFERENT IODOBENZENE CONCENTRATIONS.

1, 100 pct iodobenzene.
2, 37.5 pct iodobenzene.
3, 25 pct iodobenzene.
X-ray tube voltage, 43 kv.

Before a core is used for flow experiments, values of the X-ray intensity must be measured for the core when dry and also when completely saturated with oil; these values correspond to 0 and 100 pct oil saturation. In water-flooding experiments the X-ray intensity value used for zero oil saturation is that obtained when the core is saturated with water. These values of X-ray intensity are plotted as a function of oil saturation on a semilogarithmic graph, then approximate values of saturation for intermediate intensity values are given by the straight line drawn through the intensity values at 0 and 100 pct saturation. More precise saturations are obtained by correcting for the deviation of the calibration data from a straight line. This correction obviously depends on the saturation value, and it may be readily obtained by plotting the observed deviation as a function of the saturation value, as shown in Fig 10. For example, with cores that have an absorption ratio of about 15, this correction value is minus 4.3 pct for an observed value of 43 pct oil saturation; at 60 pct saturation the correction value is minus 3.9 pct; and at 80 pct, minus 2.4 pct.

TABLE 1—*Calibration Data for Core P-10*

Date	Time of Experiment	Saturation	Desaturation	I/I_f[a] X-ray Intensity (Average)	Percentage of Saturation	
					Weight	Range of Core (X-ray)
12-10-45	2:30	X		13.18	21.8	9-43
12-11-45	11:20	X		5.10	55.9	48-59
	2:15	X		4.35	64.4	59-66
12-12-45	9:10		X	6.30	47.4	44-50
	1:00	X		2.81	84.8	59-100
	2:40		X	3.33	75.0	61-85
	4:15		X	5.65	52.1	47-54
12-13-45	9:20		X	6.92	45.6	37-46
	12:50	X		2.57	87.0	63-100
	3:30		X	6.42	44.5	39-50
12-14-45	10:30	X		2.20	93.4	76-100
	12:50		X	6.16	45.9	43-50
12-17-45	10:30		X	6.66	44.7	39-47
12-18-45	9:30		X	8.89	35.6	17-40
	2:00	X		3.22	79.2	60-98
	4:10		X	3.82	67.7	59-80
12-19-45	10:50		X	4.76	55.1	46-67
	2:05		X	6.50	45.6	39-50
12-20-45	10:30		X	8.25	37.5	24-41
	3:25	X		2.23	94.0	77-99

[a] $I/I_f = \dfrac{\text{Intensity in IC-20}}{\text{Intensity in IC-3}}$

TABLE 2—*Calibration Data for Core B-1*

Date	Time of Experiment	Saturation	Desaturation	I/I_f[a] X-ray Intensity (Average)	Percentage of Saturation	
					Weight	Range of Core (X-ray)
12-10-45	1:15	X		5.91	56.9	51-69
	4:00	X		5.83	62.2	59-67
12-11-45	10:45			6.05	62.0	57-67
	1:25	X		5.93	65.7	61-68
	3:35		X	8.21	49.0	47-51
12-12-45	10:10		X	10.05	39.2	34-42
12-13-45	2:30	X		3.49	88.5	65-100
	4:10		X	12.30	30.6	0-39
12-14-45	11:20	X		2.96	94.0	74-94
	1:45		X	16.90	25.4	0-31
	3:45	X		2.81	97.0	81-100
12-17-45	9:30			2.85	95.9	76-100
	1:50		X	17.04	25.8	0-31
	4:00	X		5.00	73.0	62-83
12-18-45	10:15			4.84	72.9	63-85
	1:00	X		3.27	90.2	71-100
	3:20		X	3.86	80.9	72-90
12-19-45	10:00		X	4.87	68.0	61-78
	1:10		X	7.18	50.3	47-58
	3:10		X	16.06	26.6	0-33
12-21-45	10:30	X		2.60	96.1	84-100

[a] $I/I_f = \dfrac{\text{Intensity in IC-20}}{\text{Intensity in IC-3}}$

Although the use of these correction values has increased the accuracy of the oil-saturation measurements, it should be noted that when using 25 pct concentration of iodobenzene fluctuations in the X-ray source may lead to errors that are of the same order of magnitude as the correction values. On the other hand, it is felt that even at the present stage of development the above described method is sufficiently accurate, reproducible, and rapid for direct application to the determination of permeability-saturation characteristics of oil-field cores. This particular application will be discussed in detail in a later paper. To show, however, the wide range of problems that can be studied with the aid of the X-ray absorption technique, a few examples will be given in the following section of typical fluid displacement and redistribution experiments, although it

TABLE 3—*Typical Calibration Measurements for Core P-10*

Date and time of Experiment....	12-12-45, 9:10				12-18-45, 4:30			
Core Position	X-ray Intensity			Percentage of Saturation, Calibration Curve	X-ray Intensity			Percentage of Saturation, Calibration Curve
	IC-3(I_f)	IC-20(I)	I/I_f		IC-3(I_f)	IC-20(I)	I/I_f	
5½.............	0.0251 v.	0.166 v.	6.60	44.9	0.0234 v.	0.110 v.	4.71	58.9
5¾.............	0.0252	0.162	6.42	45.8	0.0233	0.108	4.65	59.3
6...............	0.0251	0.167	6.62	44.8	0.0232	0.105	4.53	60.5
6¼.............	0.0254	0.169	6.68	44.3	0.0232	0.102	4.40	62.0
6½.............	0.0254	0.163	6.42	45.8	0.0230	0.0920	4.00	66.2
6¾.............	0.0254	0.158	6.25	46.5	0.0228	0.0810	3.56	71.9
7...............	0.0253	0.155	6.12	47.7	0.0228	0.0747	3.27	75.9
7¼.............	0.0252	0.151	6.00	48.2	0.0228	0.0701	3.09	78.9
7½.............	0.0253	0.147	5.81	50.0	0.0228	0.0687	3.01	79.8
7¾.............	0.0252	0.153	6.08	48.0	0.0227	0.0689	3.02	79.7
Average.......			6.30	46.6			3.82	60.3
Weight of core and liquid, grams..	182.406				184.294			
Weight of core, grams.............	178.016				178.016			
Net weight of liquid, grams........	4.390				6.278			
Weight for 100 pct saturation grams..........................	9.248				9.248			
Saturation by weight, pct.........	47.4				67.7			

TABLE 4—*Typical Calibration Measurements for Core B-1*

Date and Time of Experiment....	12–11–45, 3:35				12–17–46, 4:00			
Core Position	X-ray Intensity			Percentage of Saturation, Calibration Curve	X-ray Intensity			Percentage of Saturation, Calibration Curve
	IC-3(I_f)	IC-20(I)	I/I_f		IC-3(I_f)	IC-20(I)	I/I_f	
5½.............	0.0230 v.	0.179 v.	7.79	50.7	0.0240 v.	0.0902 v.	3.76	82.9
5¾.............	0.0229	0.191	8.35	47.4	0.0239	0.106	4.45	75.1
6...............	0.0229	0.189	8.29	47.8	0.0238	0.114	4.79	72.0
6¼.............	0.0228	0.190	8.32	47.6	0.0238	0.116	4.88	71.1
6½.............	0.0229	0.189	8.29	47.8	0.0239	0.117	4.90	70.9
6¾.............	0.0231	0.189	8.19	48.2	0.0238	0.122	5.12	68.8
7.............	0.0231	0.187	8.10	48.9	0.0239	0.125	5.23	67.9
7¼.............	0.0231	0.194	8.39	47.2	0.0240	0.128	5.32	67.1
7½.............	0.0232	0.190	8.19	48.2	0.0237	0.131	5.52	65.7
7¾.............	0.0232	0.191	8.22	48.0	0.0238	0.144	6.03	61.8
Average.......			8.21	48.3			5.00	70.3
Weight of core and liquid, grams...	178.361				180.448			
Weight of core, grams.............	174.158				174.158			
Net weight of liquid, grams........	4.203				6.290			
Weight for 100 pct saturation, grams..........................	8.600				8.600			
Saturation by weight, pct.........	49.0				73.0			

should be understood that these are of only illustrative significance and are not to be construed as complete quantitative studies.

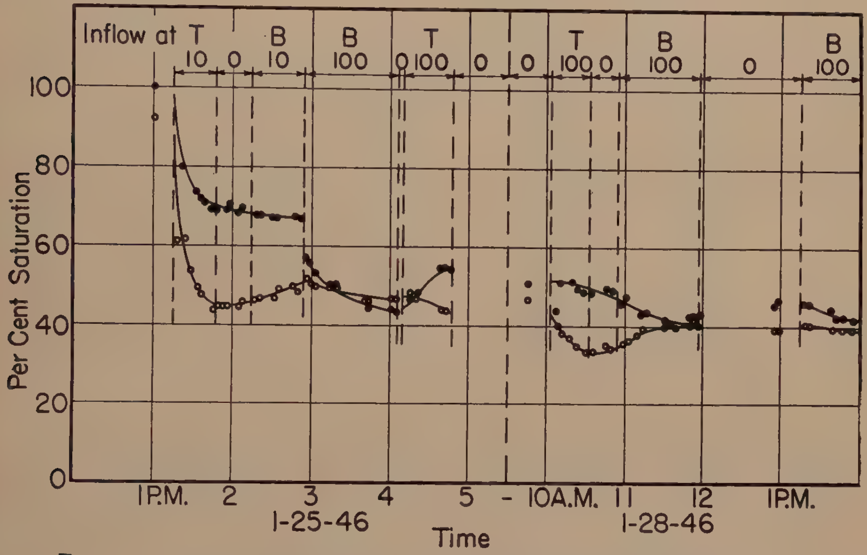

FIG 11—EFFECT OF DIRECTION OF GAS FLOW ON DISTRIBUTION OF OIL SATURATIONS AT ENDS OF CORE B-2 IN VERTICAL POSITION WITH NO CONNATE WATER.

T and open circles, top of core.
B and black dots, bottom of core.

Numbers at top give gas-flow rates in cc per min.

MULTIPHASE FLOW EXPERIMENTS USING X-RAY METHOD TO MEASURE OIL SATURATION IN CORE

The saturation measurements reported in connection with the following experiments were obtained by the X-ray absorption method. In all experiments the average X-ray intensity was obtained for the dry core before water or oil saturation and, where possible, for the core at 100 pct oil saturation. In experiments where complete oil saturation of the core was not observed, the value of the average X-ray intensity for 100 pct saturation was estimated by using the absorption coefficient for the same core or similar core obtained in a previous experiment.

As indicated in the discussion of the calibration data, the assumption of simple exponential absorption between the limits of saturation introduces an error in the observed oil saturation as much as 4 pct at 50 pct oil saturation. Inasmuch as the following experiments were made to evaluate the possibilities of the method regarding the qualitative effects of gas flow, water-flooding, and oil-flooding on the oil distribution within a core, this error in the absolute saturation value was not considered to be of major importance. In further quantitative flow studies and permeability measurements it would be essential to calibrate each core by X-ray intensity measurements at intermediate oil saturations as well as at 0 and 100 pct saturation.

Effect of Gas-flow Reversal on Oil Distribution in Cores without Connate Water

The experiments giving the results plotted in Fig 11 were performed to show the effect on the saturation near the ends of a core when the direction of gas flow is changed.

A gas-flow rate of 10 cc per min to the top of the core B-2 after initial oil saturation reduced the saturation during an interval of 30 min to 45 pct at the inflow end and about 68 pct at the outflow (bottom) end—a saturation differential of 23 pct. At this saturation there was only slight oil redistribution during a 30-min interval of no flow. Reversal of the gas flow at 10 cc per min gradually reduced the saturation differential from 23 pct to about 17 pct without appreciable change in average saturation of the core.

However, when the gas-flow rate was increased to 100 cc per min to the bottom of the core the saturation differential decreased rapidly, and after 60 min the outflow end showed 47 pct oil saturation—about 2 pct greater than the inflow end. By again reversing the gas flow, 100 cc per min to the top of the core, a definite redistribution of the oil was observed, and during an interval of 40 min the saturation differential increased from 2 to 11 pct with the outflow end at the higher saturation; that is, 54 pct. Then during 66 hr without gas flow, the oil in the core redistributed itself without change in average saturation value to a saturation differential of only 4 pct.

The effect of gas-flow reversal was again observed at an average oil saturation of 42 pct. With a gas-flow rate of 100 cc per min to the top of the core the saturation differential increased from 4 to 15 pct during a 30-min interval, the outflow end having the higher saturation value of 48 pct. Without gas flow little change in oil distribution was observed after 25 min. However, with a gas-flow rate of 100 cc per min to the bottom of the core the saturation differential again was reduced to practically zero with an average oil saturation of 42 pct. During 60 min without gas flow the saturation differential increased to 7 pct, indicating redistribution of the oil within the core.

These experiments indicate the effect of reversal of gas flow on the oil distribution in the core. At low rates of gas flow, about 10 cc per min, the change of saturation differential was slow and limited except when applied to a fully saturated core. At higher rates of gas flow, about 100 cc per min, a considerable redistribution of the oil was effected by a change in direction of gas flow. For upward flow of gas at 100 cc per min, the saturation differential was only several per cent, while for downward flow of gas at 100 cc per min the outflow end showed a saturation 11 pct higher than the inflow. In addition, a redistribution of oil in the core without gas flow was observed at core saturations of 48 and 42 pct.

Oil and Water-flooding of Saturated Cores

To obtain quantitative measurements of the saturation differentials in oil-water phase systems, core B-2 was saturated with water and then oil-flooded. With the X-ray method the displacement of the water as oil flowed to the bottom of the core could be readily followed. Curve *a* of Fig 12 shows the initial displacement of the water by the oil entering the bottom of the core; within ½ in. along the length of the core the oil saturation decreased from 46 pct to 0, indicating a high saturation gradient at the water-oil interface. With additional flow of oil through the core an oil saturation of about 51 pct was obtained (curve *b*). Higher oil saturations were obtained by increasing the inlet pressure to give higher rates of oil flow. These flow effects on the oil distribution are shown in curves *c*, *d*, and *e*. Finally, with oil flow at an inlet pressure of 30 psi, an oil saturation of 81 pct was obtained, as shown in curve *f*.

The effects of water-flooding this core containing connate water and oil are shown in curves *g*, *h*, *i*, *j*, and *k*. Curve *g* shows the redistribution of oil, from the distribution of curve *f*, during 18 hr of standing. The rapid oil displacement by water flow to the top of the core at an inlet pressure of 6 psi is shown in curve *h*.

Curves *i* and *j* indicate the effects on oil distribution in the core as water flowed to the top of the core at inlet pressures of 10 and 26 psi, respectively. Curve *k* shows the oil distribution after considerable water flow to the top of the core at a pressure of 26 psi.

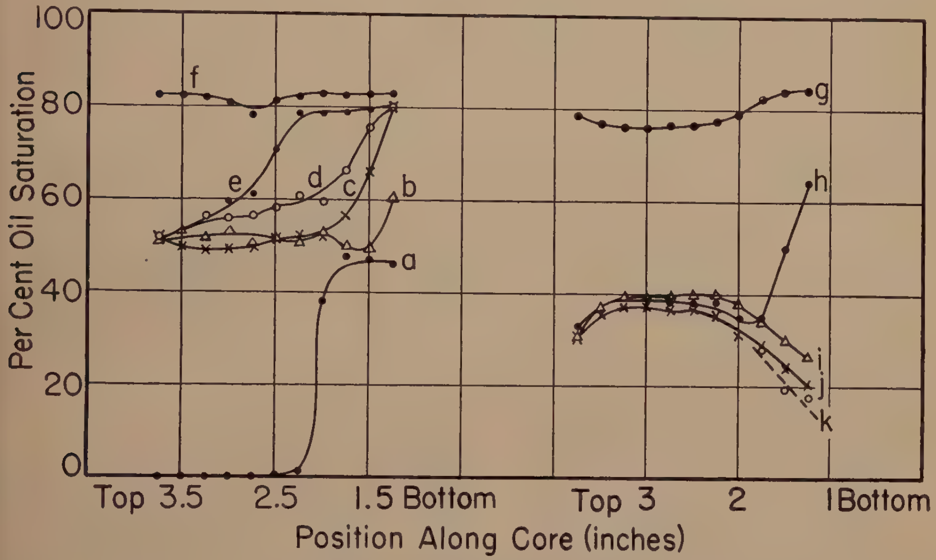

FIG 12—OIL-SATURATION DISTRIBUTIONS IN VERTICALLY MOUNTED CORE B-2, ORIGINALLY WATER-SATURATED.

Curves *a* to *f*, during initial oil-flooding at bottom. Curves *g* to *k*, during subsequent water-flooding at top.

Gas-drive on Horizontal Cores

Another gas-flow experiment was performed with the oil-saturated core in a horizontal position to show the saturation differentials obtained at several gas-flow rates. The effect of gas-flow reversal at a rate of about 200 cc per min was measured with the core at approximately 50 pct oil saturation. The data for this experiment are plotted in Fig 13.

As in the previous experiments with vertical flow, the oil saturation decreased whenever the gas-flow rate was increased. The differences in oil saturation at the ends of the core increased by several per cent as the average saturation decreased. Curve *e* shows the redistribution of oil during an 18-hr interval without gas flow. The increase in average oil saturation probably is due to oil flow into the core from the reservoir at the end of the core. Comparison of curve *d* with curve *f* shows the effect of reversal of gas flow on the oil distribution in the core. All the saturation gradients indicate that the oil saturation varies most rapidly at the inflow portions of the core.

CONCLUSIONS

The primary object of this investigation was the development of a technique for measuring the oil saturation in cores that could be incorporated in a method for determining the permeability-saturation relationship of producing rocks, and it is felt that the method described will serve that purpose. Accordingly, further effort is now being directed toward the development of such flow systems and auxiliary facilities as will be required for the permeability measurements.

The multiphase flow experiments described should serve to show the potentialities of the X-ray method for the measurement of oil saturation in cores. In themselves, they are only of a preliminary character, and are not to be considered as complete studies of the various types of multiphase flow; in fact, it would be premature to draw any specific conclusions from these experiments, except for the general observation that end effects in small cores undoubtedly play a major role in determining the fluid distribution. Gravity also appears to be a more important factor than heretofore has been assumed. In fact, it is possible to give a qualitative explanation of most of the observations on vertical cores as resultant effects of the unidirectional action of gravity, and the capillary pressure generally tending to increase the saturation at the outflow ends of the cores. In some of the experiments these factors superposed to accentuate the saturation gradient over the core, whereas in others their effects were oppositely directed and the resultant depended on their relative magnitudes. Since these experiments are only preliminary in nature, no more detailed discussion is warranted at this time. It is proposed to follow up these preliminary experiments with a more systematic study of the detailed mechanism of oil displacement by gas and water.

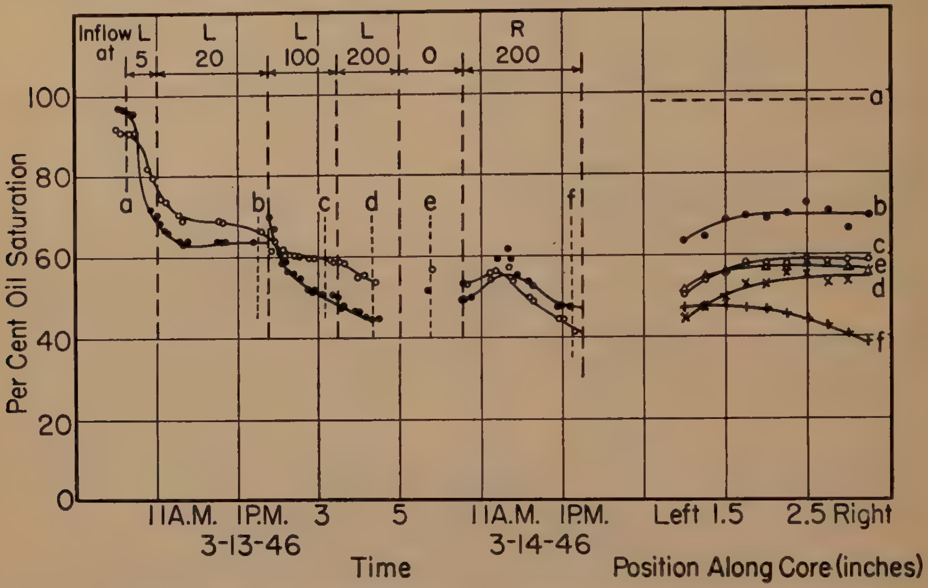

FIG 13—OIL-SATURATION DISTRIBUTIONS IN HORIZONTAL CORE B-6 UNDER GAS DRIVE, WITH NO CONNATE WATER.

R and open circles, right end of core. *L* and black dots, left end of core. Numbers at top give gas flow rate in cc per min.

Finally, it may be noted that whereas the material presented in this paper has referred exclusively to the measurements of oil saturations, the method is, in principle, also applicable to the determination of water contents of cores. By adding X-ray absorbing tracers to the aqueous phase, the same procedure provides a means for measuring the water saturation. On the other hand, when measurements of both the water and oil saturation are required it should be possible to combine the X-ray method for the oil phase with the use of a radio-active tracer in the water phase, or with conductivity measurements for measuring the water saturation. It is planned to develop this type of generalization of the technique, once the measurements for systems with only two mobile phases is established in routine form.

ACKNOWLEDGMENTS

The authors wish to thank Mr. W. L. Kehl for his contributions in the early stages of the work, Mr. D. W. Reed for mounting the cores, and Dr. Paul D. Foote, Executive Vice-President of the Gulf Research and Development Co., for permission to publish the material.

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DISCUSSION

(*John Murrell presiding*)

L. K. FREVEL.*—The accuracy and sensitivity of the proposed method suffers materially by the use of white X-rays because the mass absorption coefficients for the different components of a mixture change at different rates as the wave length is varied. This difficulty can be minimized by using a more efficient absorber than iodobenzene; e.g., methylene iodide or lead tetraethyl.[7] The selection of an ionization chamber as an X-ray detector in preference to a sensitive Geiger-Müller counter is not explained in the text. A null method using the currents from two ionization chambers opposed through a bridge network would eliminate most of the ratio calculations and should minimize errors from fluctuations of X-ray-tube power supply.

With obvious refinements, the X-ray absorption method can be developed into a valuable analytical tool.

M. MUSKAT (author's reply).—Dr. Frevel's remarks are well taken. We have been fully aware of the theoretical advantages of using a monochromatic X-ray beam, of course, but it was felt that the consequent reduction of the beam intensity and sensitivity of detection would be more serious than the slight nonlinearity in the calibration curves, using white X-rays, which can be taken into account as indicated in the paper.

We had also seriously considered the use of a variety of tracers other than iodobenzene. Methylene iodide, mentioned by Dr. Frevel, actually appears to be inferior to iodobenzene, because it has some solubility in water, and does not make a stable solution in oil. Lead tetraethyl represents an unnecessary potential health hazard because of its toxicity. We do know of other materials that could be used as substitutes for iodobenzene, and may introduce such changes in later work. However, the iodobenzene was entirely satisfactory for our present purpose, and we did not feel the need for listing or trying all such materials. Moreover, the lower concentration required for absorbers as methylene iodide or lead tetraethyl is of minor importance, since the 25 pct iodobenzene concentration does not materially affect the physical properties important to flow phenomena. Basically, the choice of the tracer is largely a matter of personal preference.

Regarding the details of experimental technique and equipment, it should be noted that the purpose of the paper is not to present a commercially salable circuit and instrument. Rather, it is only to describe a new method, based on principles previously not used in production-research flow studies, which we have found to be satisfactory. An ionization chamber was chosen as X-ray detector largely because under the particular circumstances prevailing at the time this work was undertaken its development appeared to be a simpler problem. Undoubtedly, a Geiger-Müller circuit could be used, and, in fact, such a detector was actually tried in the early phase of the work. Moreover, preliminary trials and serious consideration were given to the use of the fluorescent screen and photomultiplier tube circuit for the X-ray detection. All these represent possibilities, but we attempted to describe only the one we are using at the present time. In the same category lies the question regarding the use of a bridge circuit for directly recording the ratio of the transmitted to the incident beam intensity. This, too, has been given consideration here, and an equivalent development is under way.

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* The Dow Chemical Co.

[7] M. V. Sullivan and H. Friedman: *Ind. and Eng. Chem.*, Anal. Ed. (1946) **18**, 304.

Undoubtedly, the whole method could be developed into a variety of experimental arrangements and forms making use of the same basic principles. It is only a demonstration of the latter and of its practicability that the present paper intended to provide.

F. W. Albaugh.*—The method of saturation measurement developed by the authors represents an important advance toward the goal of a reliable and routine method for the determination of relative permeabilities. In our own relative permeability work we have found measurement of saturations by the weighing and material-balance procedure to be the principal source of error when using small cores. The X-ray absorption method appears to be attractive in all respects with the possible exception of the somewhat elaborate nature of the apparatus, the sensitivity to fluctuations in the applied voltage, and the rather extensive calibration required for very accurate work. In these respects, the use of radioactive tracers, suggested by the authors as a supplement to the X-ray method in three-phase flow experiments, should offer some advantages. Voltage control would be eliminated, and only one ionization chamber would be required. Also, gamma-ray absorption is comparatively nonspecific with respect to wave length and chemical composition of absorber material, depending primarily on the average density of the absorber. Thus, under most saturation conditions deviations from a linear saturation-ionization relationship probably could be computed with sufficient accuracy on the basis of density data. The possibility of following the oil phase by incorporating a gamma emitter such as iodine^{131} in an oil-soluble compound should also be kept in mind.

The data presented by the authors has demonstrated the value of the X-ray absorption technique in basic studies of fluid-displacement mechanisms and end effects. However, in carrying out more exact studies of this type the quantitative results could be confused by lack of uniformity of a core specimen in regard to properties such as porosity, permeability, curvature-saturation. Fig 12, curve *g* and Fig 13, curve *e* indicate that cores B-2 and B-6, which probably were among the most uniform natural cores available, may have been somewhat nonuniform. Assuming saturation equilibrium after 18 hr of standing and neglecting the effect of the vertical position of core B-2, because of the high capillary pressure obtaining, horizontal curves would be expected if the cores were completely uniform in regard to the curvature-saturation relationship. The observed deviations from the horizontal are too small to affect in any way the qualitative significance of the results presented but do suggest that in very exact studies it may be necessary to prepare artificial cores in order to attain the required degree of uniformity.

As the authors have indicated, surface tension and interfacial tension values are regarded as having little influence on permeability-saturation relationships. However, this conclusion presumes the absence of finite contact angles; i.e., complete wetting of sand by water and of water by oil in water-oil-gas systems and of sand by oil in oil-gas systems. Very probably finite contact angles are absent in nearly all subsurface systems, but they could occur in systems wherein iodobenzene and/or white oil is employed as the oil phase. Bartell and co-workers have found that most organic liquids form a zero angle in silica-organic liquid-air systems, but iodobenzene and certain other organic halogen compounds form finite contact angles. Using calcium carbonate and alpha-bromonaphthalene or acetylenetetrabromide, which in general show the same unusual wetting behavior as iodobenzene, I have found in measuring solid-water, organic liquid, contact angles, that when the organic liquid is displacing water, which is the most favorable condition for formation of a zero angle, a finite angle is observed. Under similar conditions zero angles are obtained for most organic liquids, including hydrocarbons. The formation of oil lenses at a water-iodobenzene-air or water-white oil-air interface is well known, of course. In view of the low boundary-tension values cited for the mixture of 25 pct iodobenzene and 75 pct white oil, it appears unlikely that contact angles were a factor in the present experiments. However, this difficulty could be anticipated if very pure white oil and iodobenzene were used in flow experiments. Possibly deliberate addition of surface-active materials is indicated as a safety measure.

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It is to be hoped that the excellent pioneer work by the authors will be continued, and that the generous presentation of their method and data will stimulate others to make similar efforts and to publish their findings.

R. L. Parsons* and M. B. Standing.*—The method described is a valuable addition to the technique of laboratory measurements. The rapid and accurate measurement of the oil-phase saturation during flow is particularly impressive, especially with apparatus that is neither unusually expensive nor delicate.

While the primary object of this paper is to present the information regarding apparatus and technique, one cannot help commenting on the data presented. The data showing the liquid saturations existing after periods of gas flow are indicative of the large influence that capillary forces (the "end effect") may have in the production of oil.

It is known that interstitial water, existing in a pressure gradient in a producing sand, should flow toward the well. Once reaching the well face, the water is unable to leave the sand because of the capillary pressure between the water and the producing phase. Hence the water accumulates in the sand near the well. This reduces the productivity of the well drastically and ultimately results in a small amount of water production at a rate equal to the rate at which water flows into the region of the well from the sand body. This "banking up" process should be typical of all flowing sand-fluid systems containing two or more immiscible phases, and is shown clearly in the results of this paper.

Experimental data showing the "banking up" process at the outflow face of a sand body have been presented by Brunner and Mardock. It is also possible to obtain a good idea of the process by calculation. For example, Fig 14 presents results based on Darcy's law, the perfect gas law; Wyckoff and Botset's relative permeability data; conservation of mass, and a measured capillary pressure-liquid saturation for a consolidated core of 60 millidarcys permeability.

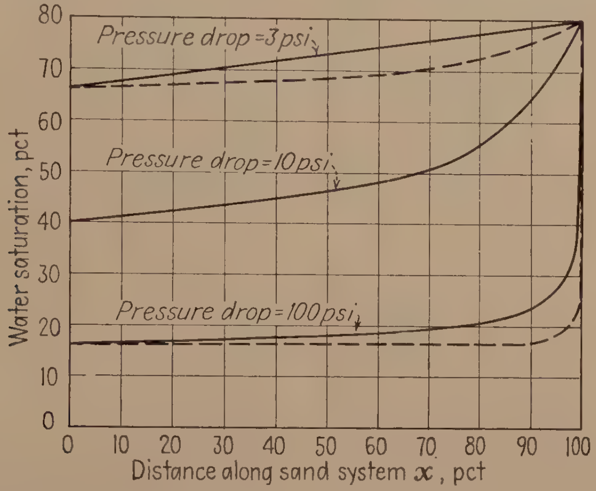

Fig 14—Water distribution at equilibrium in sand through which gas is flowing.
Gas pressure at outflow face, 15 psia.
Porosity, 20 pct.
Permeability, 60 md.
Solid line, linear flow; dotted line, radial flow.

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* Standard Oil Company of California, La Habra, California.

In conclusion, it might be pointed out that the work of obtaining permeability-saturation data on soils is analogous to determining data on core samples and that the investigators in the soil science field have been publishing data on methods and techniques since the early 1920's. While the authors state that the method outlined by Hassler in U. S. Patent 2345935 is the only method applicable to cores commonly available, one should not overlook the work of L. A. Richards, for example, appearing in *Physics* (1931) 1, 318.

R. L. Boyer, F. Morgan and M. Muskat (authors' reply).—The constructive comments of Messrs. Albaugh, Parsons and Standing are highly appreciated. Perhaps because the apparatus described in the paper is the evolutionary result of our initial development program, it may well appear to be rather elaborate and unnecessarily complicated. However, a reconstruction of the equipment, as is now being completed at our laboratory, has permitted the incorporation of material improvements in the facilities required for flow measurements, and better disposition of the electrical circuit elements, so that the apparatus as a whole is now more compact and better adapted for routine measurements.

We agree that the use of gamma-ray tracers as a supplement to the X-ray method should be thoroughly explored. It is to be anticipated, however, that the results obtained by means of the radioactive tracer would be less satisfactory than with the X-ray method, in view of recently reported studies on radioactive tracers[8] as applied to flow problems. Moreover, it is doubtful whether such supplementary techniques would in themselves obviate the need for controlling the voltage fluctuations of the X-ray beam, since in three-phase flow work one must determine the saturations of two of the phases accurately by independent means. From the work already done, it appears that the calibration curves will not need to be developed throughout the complete saturation range of interest. A single point at a medium saturation should suffice to determine the deviation from linearity with as much precision as is warranted by the accuracy that can be achieved in the permeability measurements.

The lack of uniformity inferred by Albaugh in cores B-2 and B-6 is undoubtedly the explanation for the apparently anomalous variations in the saturation-distribution curves. While rather disconcerting in itself, this observation serves to show the usefulness of the X-ray method in revealing details of rock structure and flow distribution such as would be difficult or entirely impractical to establish by any other means, except for the neutron scattering technique. For the purpose of simplifying the study of the fundamental principles of flow phenomena, it would be desirable to use cores of greater uniformity, even though they were artificially prepared, as suggested by Albaugh. In practice, however, it will be necessary to accept the irregularities inherent in natural cores in spite of the complications so introduced.

The comments of Albaugh regarding the interfacial properties of iodobenzene, water, and oil are very pertinent. No detailed study of this problem has been made, except with regard to the measurement of the surface and interfacial tensions. While neither the experiments reported in the paper nor subsequent studies have thus far revealed anomalous phenomena indicating directly the effect of nonvanishing interfacial contact angles, it will be desirable to settle this question more definitely by independent experiments.

The interpretation of the saturation distributions presented by Parsons and Standing in terms of the capillary pressure relationship is entirely correct. Since this whole problem merits a detailed study in itself, no attempt was made to include in the paper a quantitative interpretation of the observations. The purpose of presenting the data on the flow experiments was to illustrate the potentialities of the X-ray method. It was, of course, obvious that basically the variable saturation distributions in the horizontal cores were directly caused by capillary pressure and end-effect phenomena. It is interesting that the detailed calculations of Parsons and Standing qualitatively confirmed the type of distribution obtained. In fact, it is hoped that by further application of the X-ray method to this problem it will be possible to develop further data on capillary-pressure curves and the role that end effects play in flow experiments.

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[8] R. G. Russell, F. Morgan and M. Muskat: This volume, page 51.

The reference to the Hassler patent was not intended to suggest that the fundamental work of Richards and of other soil scientists was not pertinent to the permeability-saturation problem. As Hassler, Brunner and Deahl have pointed out, the basic understanding of capillary phenomena was originally developed in the soil science field. To the authors' knowledge, however, the only *published* description of a technique for actually determining the permeability curves for cores of short length is that of Hassler, although this method undoubtedly is the outgrowth of previous developments in the field of soil science.

J. M. Robinson.*—The X-ray method for measuring oil saturation of cores under flow conditions, as set forth in this paper, promises to be of considerable value in determining saturation-permeability relationships. Such a method should facilitate the study of gas or water repressuring projects, both for valuation purposes and field control.

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* Earlougher Engineering, Tulsa, Oklahoma.

Phase Relations of Hydrocarbon-water Systems

By John J. McKetta, Jr.* and Donald L. Katz,† Member AIME

(Galveston Meeting, October 1946)

Abstract

Recent experimental data on the methane-n-butane-water system have been combined with data in literature to present: (1) the water-vapor content of natural gases, (2) the solubility of water in hydrocarbon liquids, and (3) the solubility of natural gases in water.

Table 1.—*Hydrocarbon-water and Related Systems Investigated at Elevated Pressures and Temperatures*

System	Phase Compositions Reported	Maximum Conditions		References
		Temperature, Deg F	Pressure, Psi	
Hydrocarbon Systems				
A. CH_4-H_2O	Water-rich liquid	77	2,350	7, 33
	Vapor	460	10,000	18
B. C_2H_6-H_2O	*P*, *T* data only	Three-phase critical region		14
	Vapor	460	10,000	20
C. C_3H_8-H_2O	Three-phase and two-phase regions	300	3,000	3
	Hydrocarbon-rich liquid	100	192	11, 19
D. C_4H_{10}-H_2O	Hydrocarbon-rich phases	Three-phase critical		21
E. C_5H_{12}-H_2O	*P*, *T*, and over-all compositions	Three-phase critical		26
F. C_6H_{14}-H_2O	*P*, *T*, and over-all compositions	Three-phase critical		27
G. Nat. gas-H_2O	Vapor and water-rich liquid	250	5,000	6
	Vapor phase	100	2,000	2, 5, 12, 15, 22
H. Nat. gas-NaCl-H_2O	Vapor and water-rich liquid	250	5,000	6
I. Nat. gas-Glycol-H_2O	Vapor and glycol-rich liquid	100	2,000	23
J. Naphtha-H_2O	Hydrocarbon-rich liquid	431	370	9
K. Kerosine-H_2O	Hydrocarbon-rich liquid	507	750	9, 10
L. Oil-H_2O	Hydrocarbon-rich liquid	538	940	9, 10
M. Petroleum fractions-H_2O	Water-rich liquid	572	1,500	13
N. CH_4-n-C_4H_{10}-H_2O	Three-phase and two-phase regions	280	3,000	17
Inorganic Gases				
A. CO_2-H_2O	Vapor and water-rich liquid	212	10,000	29, 30, 31
B. N_2-H_2O	Vapor	464	14,700	1, 25
	Water-rich liquid	464	4,500	8, 24, 28, 32
C. H_2-H_2O	Vapor	122	14,700	1, 32
D. H_2-N_2-H_2O	Vapor	122	14,700	1
E. Air-H_2O	Vapor	100	1,500	16

Introduction

Since water is present in petroleum reservoirs, experimental data regarding the behavior of water in hydrocarbon-water systems is of increasing engineering importance. A survey of literature (Table 1) shows that data of these types are fragmentary at temperatures above the hydrate region. Experimental data taken from the authors' recent investigation of the methane-n-butane-water system are presented.[17]

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[17] References are at the end of the paper

The compositions and specific volumes of the coexisting phases were determined in the three-phase region and two-phase region at temperatures of 100°, 160°, 220° and 280°F and pressures to 3000 psia. Correlations of these data with those in the literature are presented to provide methods for predicting the behavior of naturally occurring hydrocarbon-water systems.

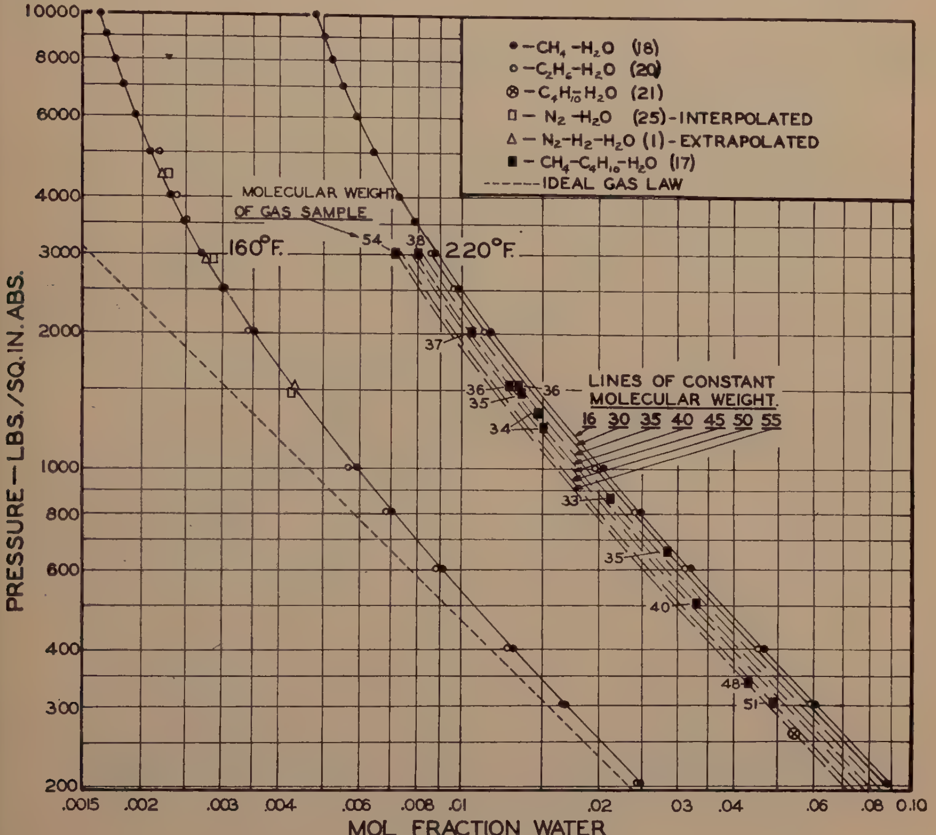

Fig 1—Water content of vapors at 160°F and 220°F.

The water contents of various vapors, the water contents of saturated hydrocarbon liquids, and the solubility of hydrocarbons in water will be discussed.

Water Content of Natural Gases

The experimental data presented by Dodson and Standing[6] relating to the composition of the coexisting vapor and liquid phases in the natural gas-water and natural gas-brine systems constitute the most complete source of published information concerning the behavior of heterogeneous systems consisting of hydrocarbons and water at elevated temperatures and pressures. Several papers[2,5,12,15,18,20,22] report the water content of the hydrocarbon phase in equilibrium with water. The data of these papers are in substantial agreement as to the water concentration at given temperatures and pressures. Fig 1, presenting data at 160°F, shows the agreement that may be expected for such systems as the methane-water, ethane-water, nitrogen-water and nitrogen-hydrogen-water systems. The dotted line represents the concentration of water calculated from the ideal gas law and the vapor pressure of pure water.

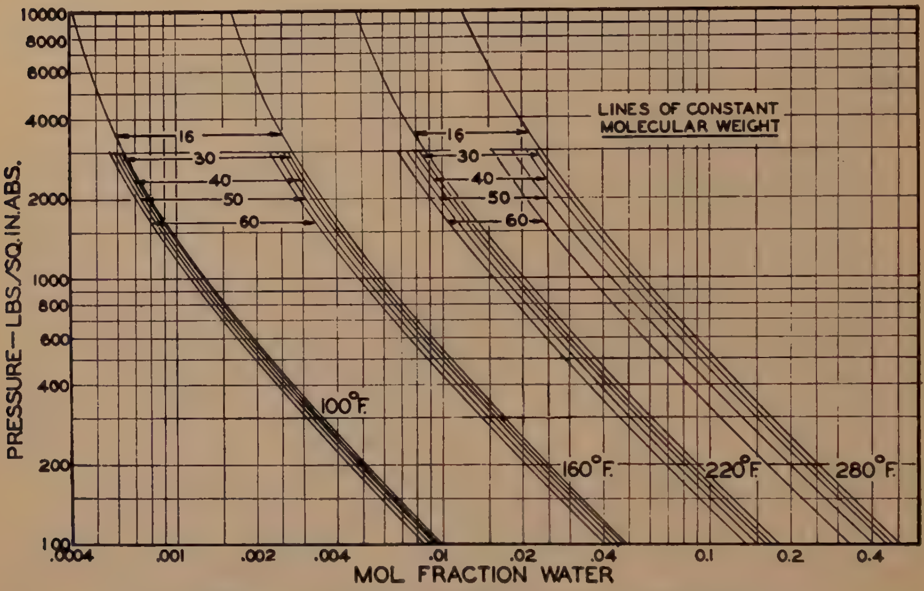

Fig 2—Effect of molecular weight on water content of vapor.

The investigation of the methane-n-butane-water system established that the composition of the hydrocarbon phase was a variable in addition to temperature and pressure. The data at 220°F from this system are plotted on Fig 1, using molecular weight to represent the composition of the hydrocarbon phase. The data of Reamer, Olds, Sage, and Lacey[18,20,21] for the methane-water, ethane-water and n-butane-water systems are in complete accord.

At temperatures lower than 220°F the methane-n-butane-water system includes dew-point gas or vapor phases having molecular weights as low as 21. The water content of these gases could have been interpolated from the methane-water and the ethane-water compositions at the same temperature and pressure. Fig 2 presents the smoothed results of the methane-n-butane-water system at four temperatures, including lines for various molecular weights.

Dodson and Standing[6] have presented a chart of the water content of "dry" natural gas (gravity 0.655) and their results are reproduced on Fig 3. The curves from 5000 to 10,000 psia are based on the methane-water system.[18] The data at temperatures below 100°F were taken from Deaton and Frost.[5] Fig 3 may be used to predict the water content of gases up to about 0.70 gravity and should apply for dew-point gases as well as for dry gases. For gas gravities above 0.70 or for molecular weights above 20, Fig 2 will indicate the correction that should be applied to Fig 3.

The foregoing discussion all relates to pure water-hydrocarbon systems. Reservoir water normally contains dissolved salts, which reduce the concentration of water in the equilibrium gas phase. The correction for brine concentration, from Dodson and Standing,[6] given on Fig 3 is based on data for gases over brines having 8600 and 34,000 ppm of sodium chloride.

The yield of water in the separator on a condensate well, producing natural gas at its dew point with respect to water in the reservoir, may be predicted by reading the content of the water in the gas for the two equilibrium conditions from Fig 3. A condensate well producing from a reservoir at 210°F and 4900 lb had an actual yield of 0.63 bbl of water per million cubic feet of gas when separated into gas and liquids at 102°F and 2200 lb. Fig 3, without brine correction, reads 0.76 bbl per million of water in the reservoir gas and 0.11 bbl of water in the separator gas for a calculated water production of 0.65 bbl per million. A calculation of the water dissolved in the hydrocarbon condensate (21 bbl per million) indicated that only 0.3 pct of the water leaving the vapor phase was dissolved in the hydrocarbon condensate and that 99.7 pct of the water leaving the vapor occurred as the water-rich phase.

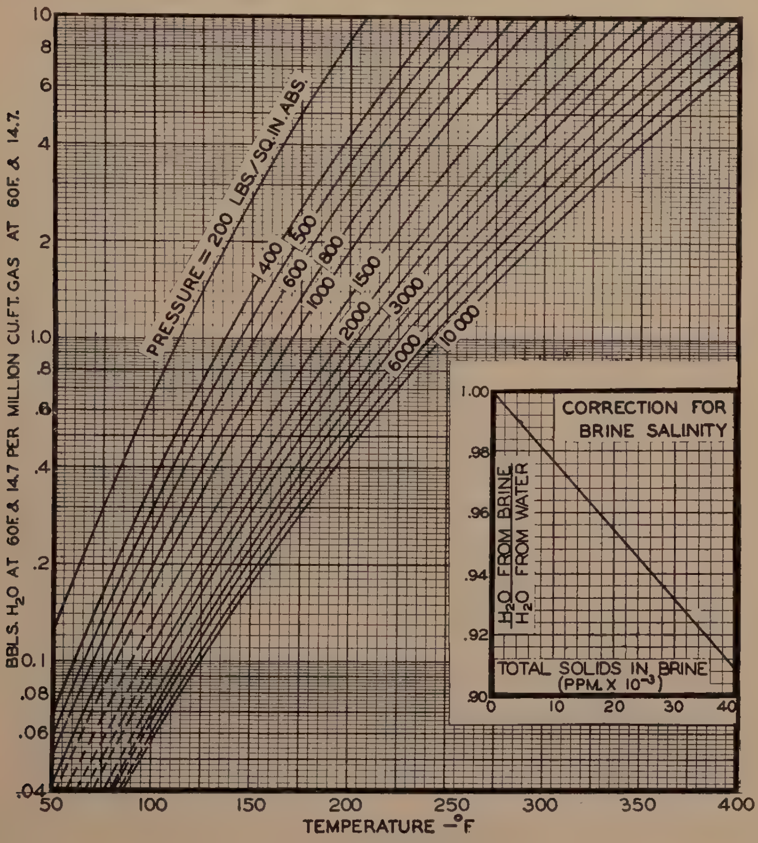

FIG 3—WATER CONTENT OF VAPORS.
Taken from data of literature.[5,6,18]

SOLUBILITY OF WATER IN LIQUID PARAFFIN HYDROCARBONS

Only a few data regarding the solubility of water in liquid paraffin hydrocarbons have been presented in the literature. This is especially true for hydrocarbon liquids with molecular weights of less than 100. No data were found on the water content of condensates or crude oils containing dissolved gases.

The experimental results on the solubility of water in the hydrocarbon-rich liquid phase of the methane-n-butane-water system[17] are presented in Table 2.

TABLE 2.—*Solubility of Water in Hydrocarbon-rich Liquid Phase of Methane-n-butane-water System*[17]

Temperature, Deg F	Pressure, Psia	Mol Weight Liquid Hydrocarbon	Mol Fraction[a] Methane in Liquid	Water Content Mol Fraction
100	202	55.2	0.0694	0.000654
	212	56.1	0.0480	0.000692
	474	51.9	0.1479	0.000809
	631	49.4	0.2076	0.000838
	979	45.2	0.3070	0.000871
	1,220	41.9	0.3860	0.00082
	1,406	39.2	0.4505	0.000864
	1,838	31.8	0.6240	0.000824
	1,880	31.1	0.6420	0.000828
	1,900	30.0	0.6690	0.000831
	1,910	28.8	0.6975	0.000832
	1,912	28.1	0.7130	0.000835
160	192	57.0	0.0266	0.00242
	535	52.5	0.1348	0.00300
	604	51.5	0.1568	0.00280
	1,022	45.8	0.2938	0.00309
	1,051	45.6	0.2975	0.00327
	1,479	39.7	0.4380	0.00350
	1,635	37.2	0.4965	0.00352
	1,683	36.6	0.5105	0.00350
	1,729	35.7	0.5330	0.00355
	1,796	33.8	0.5795	0.00370
	1,810	32.9	0.6000	0.00360
220	301	57.5	0.0155	0.00880
	338	57.0	0.0267	0.00882
	500	54.9	0.0775	0.00980
	651	52.8	0.1264	0.01020
	1,066	47.1	0.2620	0.01148
	1,241	44.6	0.3202	0.01238
	1,316	43.5	0.3476	0.01255
	1,460	40.8	0.4105	0.01172
	1,499	39.8	0.4360	0.01276
	1,520	39.0	0.4545	0.01288
280	500	57.9	0.0053	0.0274
	608	55.5	0.0624	0.0318
	665	54.3	0.0906	0.0341
	720	53.6	0.1067	0.0371
	805	52.3	0.1378	0.03815
	895	51.1	0.1680	0.04285
	948	50.2	0.1880	0.0456

[a] Water-free basis.

In Table 3 are presented similar data from the literature for molecular weights of less than 100. Additional data have been reported by Griswold and Kasch[9] and by Groschuff[10] on liquid paraffin hydrocarbons with molecular weights of 147 to 425. Fig 4 indicates that no simple correlation employing molecular weight exists on the solubility of water in hydrocarbon liquids.

The data at 160°F from Table 2 are shown graphically in Fig 5, where the mol

TABLE 3.—*Solubility of Water in Hydrocarbon Liquids of Molecular Weights Less than 100*

Hydrocarbon Liquid	Molecular Weight	Reference	Temperature, Deg F	Pressure, Psia	Water Content Mol Fraction
Propane	44	11	100	196	0.000690
		19	100	196	0.000612
Propane	44	3	80	165	0.00092
			80	165	0.00089
			100	196	0.00114
			125	261	0.00127
			150	356	0.00156
			180	498	0.00177
			190	200	0.00350
			190	560	0.00180
			190	1,500	0.00190
			190	2,500	0.00210
			195	582	0.00182
			205.7[a]	646[a]	0.00192
n-butane	58	21	100	52.45	0.0005
			130	82.8	0.0010
			160	125.4	0.0021
			190	182.8	0.0043
			220	259.3	0.0085
			250	360.0	0.0157
			280	490.0	0.0268
			300	600.5	0.0317
			305.6[a]	637.5	0.0483
Gasoline	95	4	77	14.7	0.000525
			100	14.7	0.000763

[a] Critical state.

TABLE 4.—*Smoothed Data on Solubility of Hydrocarbons in Water-rich Liquid Phase in Methane-n-butane-water System*

Temperature, Deg F	Pressure, Psia	Mol Fraction		
		In Vapor Phase	In Water-rich Liquid Phase	
		CH_4	CH_4	C_4H_{10}
100	500	0.8500	0.00062	0.000076
	1,000	0.8820	0.00112	0.000062
	1,500	0.8670	0.00154	0.000046
	2,000	0.7310	0.001868	0.000032
	3,000	0.7325	0.002414	0.000086
220	500	0.4325	0.000286	0.000242
	1,000	0.5945	0.00081	0.00019
	1,500	0.5345	0.00128	0.000123
	2,000	0.4945	0.00158	0.00017
	3,000	0.4915	0.00208	0.00024

fraction of water is shown as a function of pressure. Included in Fig 5 is the solubility of water in the vapor phase that coexists with the water-rich and hydrocarbon-rich liquid phases. At pressures below 1815 psia, if the correct over-all composition is maintained, the methane-n-butane-water system exists in the three-phase region.

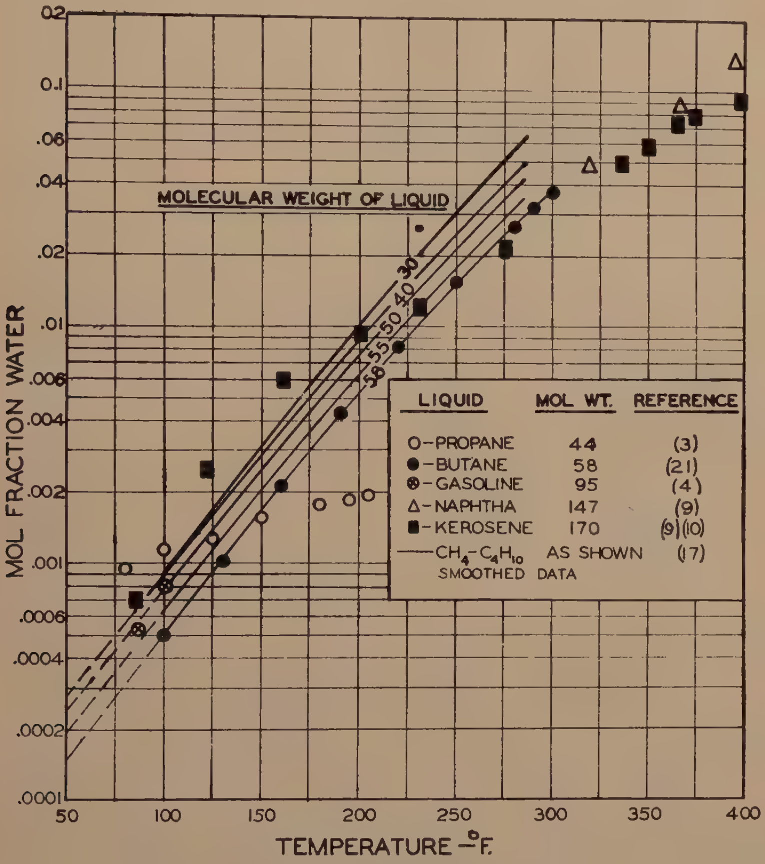

FIG 4—EFFECT OF MOLECULAR WEIGHT ON SOLUBILITY OF WATER IN LIQUID HYDROCARBON AT TOTAL PRESSURE OF SYSTEM.

The behavior of a reservoir fluid at its dew point may be followed qualitatively on Fig 5. Point *A* represents the water concentration in the single phase in the reservoir at 220°F and 3000 psia. This concentration may be predicted from Fig 3. As the fluid flows up the well, the decrease in temperature and pressure will cause a hydrocarbon-rich (condensate) phase and a water-rich phase to separate. At 160°F and 1000 psi, points *B* and *C* represent the concentration of water in the gas phase and in the condensate, respectively. If naturally occurring systems follow the methane-n-butane-water system, the dissolved water content of the condensate phase will be less than that of the gas phase on a mol-fraction basis.

Water dissolved in hydrocarbon condensate may be a vital factor in the corrosion occurring in the tubing of condensate

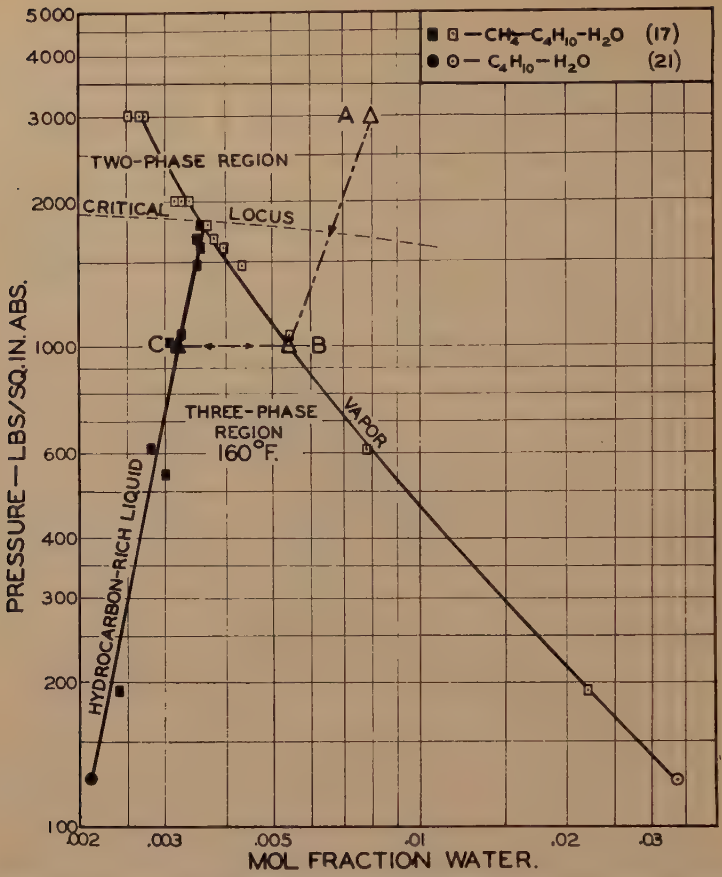

Fig 5—Solubility of water in vapor, fluid and hydrocarbon-rich liquid phases at 160°F in methane-n-butane-water system.

wells. From this research, one would expect the water content to range from about 0.1 mol pct at 100°F to about 1 pct at 200°F, with only minor effects due to pressure in this temperature range.

Table 5.—*Solubility of Nitrogen in Water*[8,24]

Temperature, Deg F	Pressure, Psia	Solubility of Nitrogen[a]
77	1,470 1,838 2,940 4,410	6.26 8.48 13.90 19.15
200	1,470 1,838 2,940 4,410	5.89 6.92 12.70 16.29

[a] Solubility is expressed in cubic feet of nitrogen at 60°F and 14.7 psia per barrel of water at 60°F and 14.7.

Solubility of Gases in Water

Natural gas is much less soluble in water than in hydrocarbon liquids. Nevertheless, natural gas does dissolve in water and the ability of reservoir waters to dissolve gas is of interest. Fig 6 presents the solubility of natural gases in water taken from the literature and this research.

In the methane-n-butane-water system at pressures above 400 lb, the methane is more soluble in the water than butane; i.e., the ratio of concentration of methane

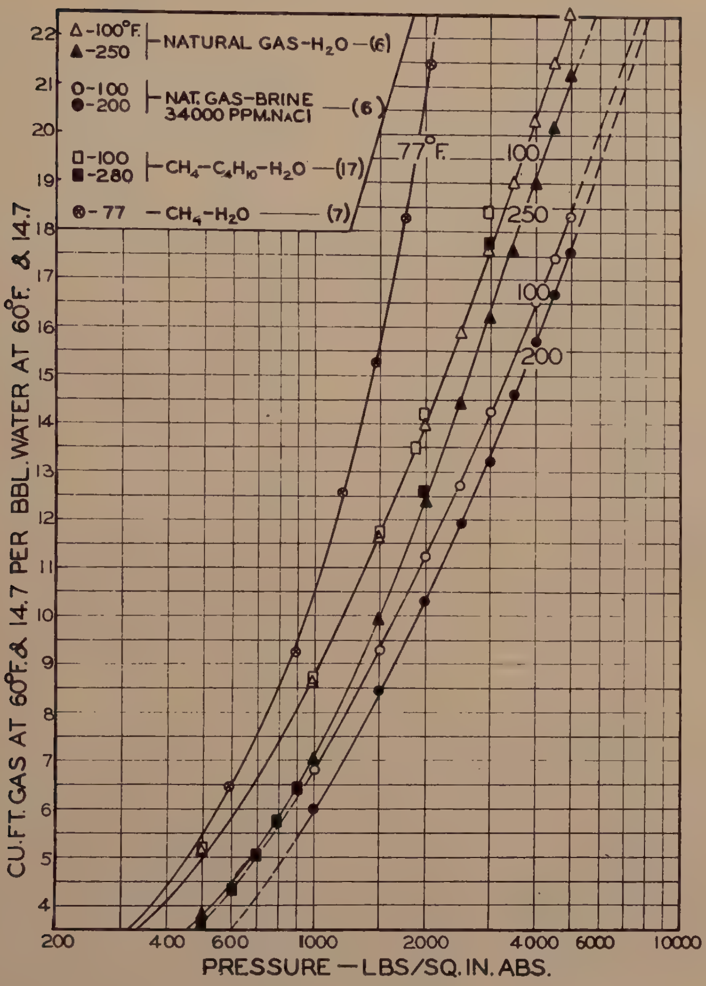

FIG 6—SOLUBILITY OF HYDROCARBONS IN WATER.

in the gas to the concentration of methane in the water is lower than a similar ratio for butane. Table 4 shows typical smoothed data.

Some of the experimental data on the solubility of nitrogen in water[8,24] are tabulated in Table 5. It is interesting to note that these data for nitrogen are in the same range as natural gas.

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DISCUSSION

T. S. BACON*—I have found this paper to be extremely interesting, and would particularly like to commend the authors on the clear and useful graphical presentations of the data.

Any paper of this type should have both accuracy and utility. It is nice to note that the results are plotted in terms that may be readily understood by the average engineer. However, in passing, I would like to take exception to the term "barrels of water" as shown in Figs 3 and 6. The oil fraternity ordinarily assumes that a barrel contains 42 gal. However, I understand there are exceptions to that outside the oil fraternity, and, for that reason Figs 3 and 6 might be less ambiguous if plotted to show pounds of water per million cubic feet of gas.

E. G. Hammerschmidt presented a paper on Equilibrium Water Vapor Content of Compressed Gases before a meeting of the Technical Section of the American Gas Association in June 1946, and included a chart that is essentially comparable with Fig 3 in the paper under discussion. There appears to be some slight discrepancy between the two and I would be interested in any comments on the probable reasons for these discrepancies. I understand that both charts are based on studies of values in the literature, and, therefore, should be comparable.

Fig 5 is of particular interest in covering the liquid-phase solubilities, which have been badly neglected previously. The importance of these solubilities is emphasized in this figure and the presentation of the available data in this form should be extremely helpful to engineers concerned with water distribution. The authors indicate only minor effects due to pressure on the mol fraction of water dissolved in the liquid hydrocarbon phase. However, other factors, such as the presence of appreciable amounts of aromatics or of naphthenics in the hydrocarbon phase and the presence of various salts in the water phase, might conceivably affect the amount of water solubility materially. It seems to me that some approximation of the magnitudes of the possible effects of these variables on water solubility in liquid hydrocarbons would be of practical benefit.

R. L. HUNTINGTON*—The authors have done an excellent piece of work in obtaining new data, and bringing together the results of other investigators into convenient graphical plots. Only workers who have actually carried out laboratory determinations on water contents can testify to the trials and tribulations of such studies.

In addition to analyses of reservoir performance, hydrocarbon-water data are invaluable in the design of gas and liquid dehydrators needed in connection with gas transmission, and catalytic reactions.

The demand for brevity in the presentation of technical papers may have been the cause for the failure of the authors to print their data in tabular form, on the methane-normal butane-water system in the gaseous phase, as well as an account of the experimental methods used in the determination of the water content in the respective phases. The absence of such information in published papers puts the investigator, as well as the process designer, in the dark in judging the accuracy of smoothed data curves, especially when observed data points do not appear on the graphs. For example, mol fractions are reported from 4 to 6 decimal points in Table 2; the reader is at a loss therefore to know where the accuracy of the experimental data actually falls.

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Before a complete picture can be presented on this phase study, new experimental methods will be needed to give the investigator rapid and more accurate means of determining the water content both in the gas and liquid phases. From a glance at the Literature Cited, it would appear that this field has been thoroughly investigated, but closer analysis of the problem reveals the fact that many new phases need to be studied before the engineer can tread on safe ground in his design and performance calculations.

Geothermal Gradients in Mid-Continent and Gulf Coast Oil Fields

By Earl A. Nichols,* Junior Member AIME

(Galveston Meeting, October 1946)

The purpose of this paper is to present a contour map that shows the geographical variation in geothermal gradients in the Mid-Continent and Gulf Coast oil fields.

INTRODUCTION

Frequently there arises the need for an estimation of the temperature to be expected at a predetermined depth in working with a wildcat or in deepening old production into zones that are relatively unknown. The study of geothermal gradients in oil fields has been made previously by many investigators. One of the pioneers in this work was C. E. Van Orstrand,[1] who, as well as most of the other investigators, was primarily interested in the relation between temperature and depth in a given locality. Between 1921 and 1929, American Petroleum Institute Research Project No. 25 fostered a thorough study of earth temperatures.[2] R. W. French did some work in California, the results of which were published in 1939.[3] In most of these studies, an attempt was made to correlate temperatures in a rather localized area. This paper will show the results of an attempt to correlate temperature gradients over rather large portions of the Mid-Continent and Gulf Coast area.

METHOD OF OBTAINING DATA

It has been found that for complete thermal equilibrium to be established in a well, the well must stand undisturbed for a period of several hours to several weeks, depending upon the way the well was produced prior to the shut-in period.

The data in this paper were obtained in conjunction with running pressures in wells or in taking samples of reservoir fluid. Glass maximum recording thermometers were used in all but a few instances. The wells had been shut in from one hour up to 10 or 12 days. Since the wells were normal producing wells, some of the shut-in times undoubtedly were insufficient for complete thermal equilibrium to have been established and the temperatures measured do not necessarily represent the true earth temperatures. They do represent the temperature conditions that will be encountered in a well that is producing oil. The data, therefore, can be useful in working with or in estimating the temperatures to be expected in producing reservoirs.

In obtaining a thermal gradient by dividing the difference in temperature of the formation and the mean annual surface temperature by the depth of the formation, one is assuming the depth-temperature line to be straight. Depth-temperature curves are almost straight lines (Fig. 1). However, on close examination of accurate data, a slight curvature usually is observed. Most wells yield curves with slopes increasing with increasing depth. These curves are believed to be from wells that are in and are underlain by sedimentary material. Some few curves have slopes that decrease with increasing depth. These curves are believed to be from wells that are underlain rather closely by granite or some other igneous rock. Most investigators

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* Core Laboratories, Inc., Dallas, Texas.

[1] References are at the end of the paper.

have assumed a straight-line relation in calculating the thermal gradient because of the simplicity of calculating gradients from straight lines. In order to conform to the common method, the assumption of a straight-line relation has been used in this paper.

Approximately 1800 temperature measurements in 194 fields were used in this work. All of the individual measurements within a given pool were averaged and the averaged value was used in contouring. In many cases, several wells in a pool were measured. Also, many wells were measured several times over a period of years. There were other instances in which only one or two measurements were available for a pool.

The average thermal gradient was plotted on the map in the proper geographical location for that particular pool. The contour lines were then drawn in the general areas where sufficient points were available to warrant the interpretation

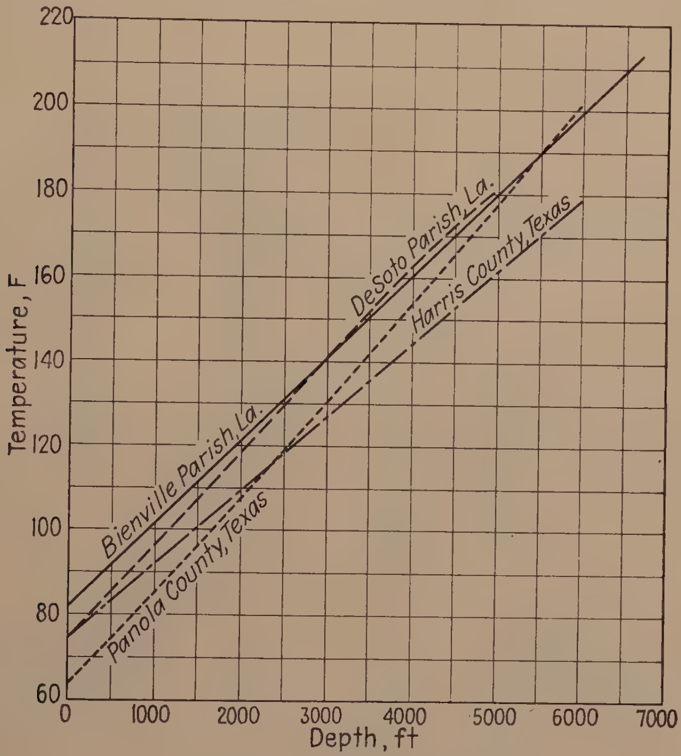

FIG. 1.—TEMPERATURE-DEPTH TRAVERSES.

presented. In many places there were too few points for accurate contouring. In these areas, either the lines were dotted or were omitted. The resulting map of geothermal gradients in oil fields is given in Fig. 2. In general, the contour interval is 0.1°F per 100 ft of depth, but where the contour lines are crowded intermediate lines were omitted.

The mean annual air temperatures measured and reported by the United States Weather Bureau for several cities in the areas under consideration are shown in Table 1. The numerical average of these values is 66°F. John A. McCutchin[4] states that "depth-temperature curves for wells in Oklahoma and Kansas intersect the temperature axis slightly above a point equivalent to the mean annual air temperature of the area where the well is located." The producing wells in which we have measured temperatures in the Mid-Continent and Gulf Coast areas have shown a tendency to intersect the temperature axis at the surface at or near 74°F. With these things in mind, a value of 74°F was chosen

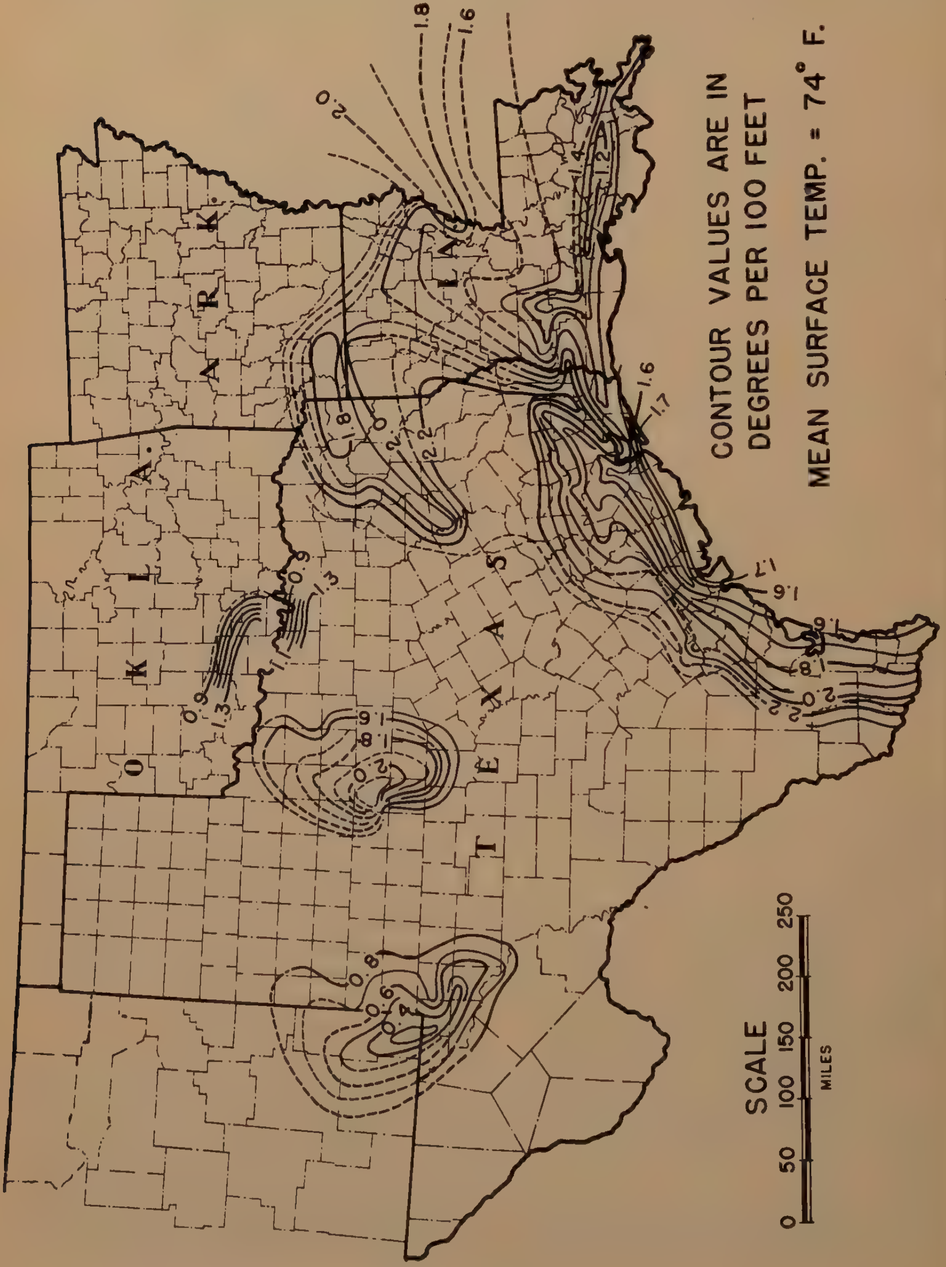

FIG. 2.—CONTOUR MAP OF GEOTHERMAL GRADIENTS IN SOUTHWEST UNITED STATES.

as the mean annual temperature to be used in conjunction with producing wells. This value was used in calculating the gradients in the paper, and as long as this same value is used in estimating temperatures with the contour map the resultant data will be reliable.

TABLE 1.—*Air Temperatures Reported by U.S. Weather Bureau*

Location		Mean Annual Air Temperature, Deg. F.
City	State	
Dallas	Texas	65.7
Houston	Texas	69.2
Corpus Christi	Texas	69.1
Brownsville	Texas	73.1
Beaumont	Texas	69.2
Gainsville	Texas	64.2
Lindale	Texas	65.5
Lafayette	Louisiana	68.0
New Orleans	Louisiana	69.6
Shreveport	Louisiana	66.0
Ardmore	Oklahoma	63.1
Oklahoma City	Oklahoma	60.1
Average		66.2

CONCLUSIONS FROM CONTOUR MAP

Certain conclusions may be drawn from Fig. 2 with greater or less assurance. It is apparent that the New Mexico-West Texas area is characterized by a low gradient basin which lies in a northwest-southeast direction. The gradients are considerably lower than those of the Gulf Coast area.

The contours along the Gulf Coast reveal several points of interest. In the general vicinity of Matagorda Bay a plateau of high temperatures appears with its axis just off shore and parallel to the shore. With the exception of this plateau, the temperature gradients elsewhere along the coast increase as one moves inland. The high-temperature plateau near Matagorda Bay and the increasing temperatures inland form a trough, which starts near Corpus Christi, runs in toward Yoakum, and finally moves back out toward the Gulf along the Mississippi Delta.

Just above the coast on the Texas-Louisiana boundary line, a rather rapid change in the temperature gradients is evident. This change culminates in a high plateau near Beaumont, Texas.

In the northeast Texas-Arkansas-Louisiana area, a large irregular basin was found in the general vicinity of the Sabine uplift. There were insufficient points to define the entire area, but a trend in southern Oklahoma seemed to be apparent in the Anadarko Basin.

APPLICATION OF CONTOUR MAP

The map may be used in estimating temperatures in the following manner:

$$\text{Estimated temp., deg F.} = [\text{Depth} \times \text{Gradient from map}] + 74^\circ\text{F}$$

In using the map, the following points should be considered. In the areas where the contour lines have been dotted, the number of control points were insufficient for accurately defining the position of the gradient lines, and they should be used with this in mind.

It is considered unwise to attempt to extrapolate the contour lines into areas that are not contoured on the map.

It should also be kept in mind that the data used in compiling this map were derived from producing wells. The data may be used for general purposes dealing with producing fields.

ACKNOWLEDGMENT

The writer wishes to acknowledge the assistance given by Dr. F. C. Kelton, Mrs. Penelope Eades, and Mr. Ed Clark. He wishes also to acknowledge the data furnished by the Phillips Petroleum Company.

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DISCUSSION

R. W. French[*]—Mr. Nichols' interesting and useful assemblage of subsurface temperature gradients furnishes information applicable to several aspects of oil production. The general correlation with major geological features, although not surprising, confirms the importance of two significant factors among those controlling earth temperatures. One of these is proximity to basement rock because geothermal gradients will increase in proportion to the proximity to basement rock in areas where other conditions are similar. The other factor that affects earth temperatures to a high degree is the relative age, especially with regard to formations that have been on or near the earth's surface long enough to become appreciably cooled as compared with those younger formations that have not experienced so much heat dissipation as a result of exposure or tectonic changes involving subsidence or emergence at relatively late dates.

In California, for example, where most producing sediments are in Tertiary section, and where comparatively recent diastrophism has taken place, geothermal gradients are relatively high. The most interesting illustration of the effects of the foregoing factors is shown on the author's geothermal contour map where the West Texas-New Mexico Region displays values far below those of the Gulf Coast—the lowest or coolest, in fact, of any oil-producing area I know.

Mr. Nichols' statement that the temperatures measured do not necessarily represent the true earth temperatures should be emphasized, since it is difficult to obtain true values unaffected by transients resulting from normal drilling or producing operations. In other words, well temperatures usually reflect previous production rate and length of the previous production period to some extent. They are affected also by the specific heat of the fluid being circulated, produced or injected as well as the interrelated variables of gas-oil ratio and varying fluid composition, not to mention thermodynamic cooling through phase changes. Temperatures measured at the bottom of a well usually are the most reliable, because less heat is transferred through fluid flow here than at any other point in the well.

In view of the low order of accuracy involved in gathering such information, as pointed out by Mr. Nichols, the conclusions drawn are interesting and helpful but should be used with caution in critical operations such as well-remedial jobs involving thermosetting plastics, cement or other chemical agents.

H. Guyod[*]—In horizontal or nearly horizontal formations the geothermal gradient is inversely proportional to the heat conductivity of sediments. Inasmuch as the regional trend of the formations for which the temperature data are available is roughly horizontal, it is obvious that the dominant feature of Mr. Nichols' map must reflect the average heat conductivity of the upper several thousand feet of sediments.

The average heat conductivity of common sediments is given approximately by the following figures ($\times 10^3$ cgs):

Rock salt	14
Anhydrite	10
Dense lime	7
Sand	4
Shale	3

Areas such as the Permian Basin, where great thicknesses of salt, anhydrite, and lime are found, should be characterized by small geothermal gradients.

Areas such as the Louisiana Gulf Coast and the shore belt of the Texas Gulf Coast, where sands and shales predominate, must exhibit relatively great gradients.

Finally, where shales predominate (inland belt parallel to the Texas Gulf Coast) the gradients must be the greatest.

The foregoing features are clearly shown by Mr. Nichols' map.

Additional secondary features, such as compaction (which increases the conductivity), and regional structures (which tilt the heat flowoff vertical), seem also to be reflected on the map.

The foregoing results are not surprising when it is remembered that a geothermal gradient map is a geophysical map. It is obvious that it must reflect the main geological features of the area considered, and that it can be interpreted in terms of geology.

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[*] Continental Oil Co., Ponca City, Oklahoma.

[*] Well Logging Consultant, Houston, Texas.

This rather lengthy academic discussion of Mr. Nichols' work should not overshadow the practical aspect of the paper.

Table 2—*Bottom-hole Temperature, State of Oklahoma*[a]

Field	Section	Township	Range	Temperature, Deg F	Depth, Ft	Gradient
Fitts	27	6S	2E	99	2,940	0.85
	27	6S	7E	112	3,200	1.19
	12	1N	7E	112	4,252	0.86
		2N	7E	107	4,000	0.83
	15	7N	4E	114	4,350	0.92
	33	7N	3E	115	4,285	0.96
	19	9N	6E	132	4,180	1.39
	3	9N	6E	129	3,680	1.5
	31	9N	9E	150	4,000	1.9
	3	10N	5E	128	4,691	1.15
	36	10N	7E	134	3,600	1.66
	35	10N	7E	124	3,250	1.54
	24	11N	2E	124	4,783	1.05
	10	12N	5E	121	4,356	1.08
	9	13N	6E	123	4,260	1.15
	35	14N	6E	127	4,197	1.26
	12	17N	1E	125	4,900	1.04
Ramsey	18	18N	2E	113	3,650	1.07
				132	4,740	1.22
	28	19N	3E	140	4,300	1.58
West Cement	35	6N	10W		6,000	0.80
North Lindsey	21	5N	4W	189	10,950	1.06
Apache	2	5N	12W	112	3,200	1.19
West Moore	29	10N	3W 2nd Wil.	152	8,756	0.89
			3W Bart.	141	7,870	0.85
Okla. City		12N	3W	132	6,500	0.89
Edmond	6	13N	3W	140	6,658	0.99
West Edmond		14N	4W	150	6,800	1.12
	33	17N	4W	149	6,150	1.22
	27	22N	2W	150	4,854	1.57

$$\text{Gradient} = \frac{\text{Temp.} - 74^\circ}{\text{Depth}}$$

[a] Compiled by Amerada Petroleum Corporation.

It is evident that the geothermal map offered will prove of value to the petroleum engineer and manufacturer for better designing the tools that have to reach the great depths at which wells are drilled at present or will be drilled several years hence.

J. A. McCutchin*—Mr. Nichols' paper is a valuable contribution to a branch of geophysics that has not been thoroughly explored. There are, for example, basic reasons to suspect that a series of earth-temperature measurements at relatively shallow depth might be used to locate possible oil or gas productive structures. Since earth temperatures always increase with depth, and since surface earth temperatures are always higher than surface air temperatures, there is a flow of heat to the earth's surface and into the atmosphere. The gradient at any point is influenced by the nature of the rock and the fluid content and it appears possible that oil and gas-saturated rock might transmit heat at a sufficiently different rate, compared with similar rock saturated with water so as to be measurable at considerable distance above the productive horizon.

Undisturbed earth temperatures at shallow depth have been found to be closely related to the mean annual air temperatures in the immediate area. In other words, if a depth-temperature curve is extended back to the point of zero depth, the earth-temperature curve will intersect the surface at a point usually about 2°F above the mean annual air temperature of the earth as recorded by the U. S. Weather Bureau. It is suggested that a more accurate estimated temperature would be obtained if the mean annual air temperature plus 2°F were used in the formula shown in the summary of Mr. Nichols' paper in place of the 74°. This figure, however, appears reasonably accurate for the Gulf Coast area.

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* Sohio Petroleum Co., Mt. Vernon, Illinois.

The relation between earth temperatures and atmospheric temperatures has proved to be a reliable check on the degree of equilibrium of well temperatures and earth-temperature gradients. Holes drilled by rotary will show temperatures much too high for shallow depth and much too low for greater depth. This is explained by the circulation of the rotary mud. Holes drilled by cable tools are known to show small deviation from true earth temperatures.

W. T. Thom first noted, about 1910, that isothermal surfaces were to be related to regional dips as a result of temperature measurements in artesian wells of South Dakota. This same relationship of relatively low temperatures in basins was also found to exist in the Anadarko basin in Oklahoma.

J. P. HAMMOND*—We have compiled a list of temperature gradients in Oklahoma that may be of interest (Table 2).

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* Amerada Petroleum Corporation, Tulsa, Oklahoma.

Some Experiments on the Mobility of Interstitial Waters

By R. G. Russell,* F. Morgan* and M. Muskat,* Member A.I.M.E.

(Chicago Meeting, February 1946)

Abstract

Core experiments with radioactive tracers are reported in which an artificial radioactive material, radiovanadium, was used in aqueous solution in a study of the mobility of connate water. Sandstone cores saturated with active water were first oil-flooded to simulate virgin sand conditions in which the pores are filled with oil and connate water. They were then subjected to flooding with inactive water. Measurements were made of the activity of various portions of the effluent as well as the activity of the core after the flooding process was completed. In additional experiments the distribution of activity along the core was measured during the flooding process. In still other experiments direct flooding tests were made on cores fully saturated with active water. In all cases it was found that after injecting into the core a volume of inactive water equal to a pore volume, the effluent contained more than 80 per cent of the active content originally in the core. It is felt that these results imply a high degree of mobility of the connate water when subjected to flooding, although at least a partial contribution of the effect of tracer transfer within the core cannot be definitely excluded. The implications of this result with respect to water-flooding, core analysis and electric logging are discussed. A better approach to determining the connate water saturation of oil-producing rocks, by measuring the fluid content of core samples at the surface, is by the use of crude oil or oil-base muds as the coring fluid.

Introduction

Although water flooding is of considerable importance in the recovery of oil, comparatively little is known with certainty about the role played by the connate water during the operations. Two possibilities exist. Either the connate water is retained in the formation while the flood water sweeps past, or it is pushed along to a greater or lesser degree by the flood. Thus far no explicit recognition in terms of quantitative studies appears to have been given to the displacement of connate waters by the intruding extraneous waters, although such a possibility might be important in determining the efficiency of the oil-displacement process in water-flooding operations, especially in argillaceous rocks. On the other hand, it is a common observation that the first water produced with the oil as a result of water-flooding is definitely saline.*[1] Similar questions regarding the mobility of the interstitial water arise in the quantitative description of the advance of edge-water drives.

In the interpretation of the water saturations determined from core analyses, when coring with water-base muds, it is generally assumed that the drilling fluid merely adds to the connate water without displacing the

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* Gulf Research and Development Co. Pittsburgh, Pennsylvania.

* C. H. Riggs,[1] in discussing water-flooding of the McClosky limestone in the Clay City field, explicitly states that the injected water displaces water from the producing zone, and estimates the fraction of formation water in the water produced from the oil wells affected by the flood.

[1] References are at the end of the paper.

latter. The determination of interstitial water saturations from measurements of the chloride content of the core is based on this assumption. While pressure core-barrel tests[2] have shown that some of the connate water may be expelled from a sand on pressure release, presumably by evolution of gas dissolved in the residual oil or interstitial water, no published data are available on the mobility of the connate water during the process of coring. The experiments discussed herein were undertaken in order to obtain an answer to this basic question. The experimental problem evidently is one of tracing and identifying the interstitial water as compared with the extraneous flooding water. For this purpose either a conventional chemical or radioactive tracer could be used. The latter, however, offers the advantage of permitting one to follow the changes in connate water content of the core as well as of the effluent, without extraction of the core, and was therefore chosen for the tests.

TRACER MATERIAL

As in the experiments to be described, a water-soluble tracer is required, the use of aqueous radium solution was, in principle, possible. However, as the result of difficulties encountered in some earlier experiments with radium tracers in oil, artificially radioactive vanadium was chosen. This tracer has the decided advantage over radium in that the gamma rays are produced during the disintegration of the radiovanadium itself. Problems arising from the possible separation of parent and daughter elements, or the escape of a gas, are consequently not encountered.

The radioactive vanadium was obtained from Dr. M. L. Pool, of the Ohio State University, where it was produced by bombarding titanium metal in the cyclotron with deuterons. Radiovanadium was chosen because it has a half-life sufficiently long (16 days) for convenient use, and because its yield from the bombardment is fairly high. Other elements could doubtless have been obtained, but this one was convenient, and for these experiments satisfactory. The samples actually used were bombarded 2 to 4 hr. In four or five days the short life elements practically disappeared, and the slope of the line for activity versus time corresponded approximately to the value expected for the 16-day half-life of radiovanadium. No attempt was made actually to utilize the tracer during the initial period of relatively rapid decay.

Chemical Preparation of the Sample

The vanadium was removed from the titanium target by milling until the activity remaining in the titanium was only about 10 per cent of the initial value, as measured by a Geiger-Mueller counter. The titanium millings were dissolved in concentrated hot HCl, the vanadium going into solution at the same time. The solution was then boiled to remove part of the acid and diluted to 100 to 200 c.c. with very dilute HCl. Addition of pure water, or too great a reduction in acidity, led to the separation of hydrous titanium oxide. An acid solution (one to three normal) prevented the formation of radio colloids.

EXPERIMENTAL RESULTS

Acid-treated cores of Nichols Buff sandstone were used. The cores were cylindrical in shape with a cross-sectional area of about 6 sq. cm., and lengths varying from 4 to 8.5 cm. Sealing along the sides was accomplished by mounting in lucite, using a technique similar to that for mounting metallographic specimens.* This material has been found to be very satisfactory when not subjected to liquids that tend to corrode the polymer and cause subsequent crazing. In Fig. 1 are shown photographs of typical mountings in plastic.

Immediately before filling, the cores were weighed, evacuated, and flushed several times with CO_2. Radioactive solution was then permitted to flow into the core while pumping was continued. In order to obtain as complete saturation as possible, a small quantity of active solution was flowed (upward) through the cores under pressure.

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* This method was suggested and developed by Mr. D. W. Reed.

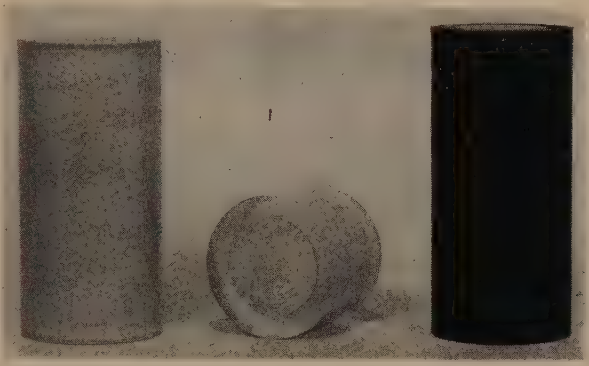

FIG. 1.—CORES MOUNTED IN LUCITE AND BAKELITE.

After a core was filled with active water, it was removed from the holder and weighed to determine the extent of saturation. A measure of the liquid content was also obtained at this time by determining the activity of the core and comparing this with a given volume of active solution. The procedure subsequently followed depended upon the nature of the experiment to be performed.

In the first type of experiment the core was replaced in the holder, which was now arranged horizontally, and a light mineral oil was flowed through it. The core was then removed, weighed, and the count determined as before. Following this, the experiment was completed by flowing inactive water, to simulate the process of water-flooding, drilling fluid invasion, or edge-water intrusion, and then measuring the water and core activities.

Two experiments were performed under conditions that were as nearly as possible identical. The oil-flooding was begun at a pressure differential of 6 lb. per sq. in. and finally raised to 80 lb. per sq. in. to obtain a maximum reduction in residual water content. For the water-flooding phase the pressure differential was of the order of 10 lb. per sq. in. and the effluent was collected in 2-c.c. portions as long as it showed measurable activity. The significant data are given in Table 1.

Almost all of the radioactive material was removed from the cores during the water-flooding process. These experiments show, in addition, that the first water coming through the core after the start of water-flooding was exceedingly rich in radioactive material. In fact, the first 2 c.c. of effluent water consisted of about 75 per cent active H_2O, and more than 80 per cent of the so-called connate water was removed in the first 4 c.c. of effluent water. It may also be noted that within experimental error there is a satisfactory balance between the initial active water content of the cores and that collected in the effluent plus the residual left in the cores.

These results may be interpreted as indicating that the active or connate water was pushed out of the cores by the inactive water as though by a loose piston. Another experiment, consequently, was performed in which an attempt was made to follow the progress of the fluids while the core was in place in the holder. To do this the core holder was mounted in a carriage that could be moved with respect to the counter by means of a screw. The experimental setup is shown in Fig. 2. As the gamma rays from radiovanadium are fairly hard, rather elaborate lead shielding was required in order to collimate the beam so that adequate resolution could be obtained. A slot ¼ in. wide was cut in the 2½-in. thick lead shield, so that radiation from approximately this length (¼ in.) of core was measured at each setting.

TABLE 1.—*Results of Experiments*

Data	Core 1	Core 2
Core volume, c.c.	32	32
Air permeability, md.	200	250
Porosity (calc. from H_2O content), per cent	21	21

Operation	Counts per Second		Liquid Content, C.C.			
			Oil		Active H_2O	
	Core 1	Core 2	Core 1	Core 2	Core 1	Core 2
Core saturated with active H_2O	14.7	14.4			6.8	6.8
Core after oil-flooding	5.3	4.8			2.4	2.3
Active H_2O removed by oil flood: calculated					4.4	4.5
Measured					4.4[a]	4.3[a]
Dead H_2O flood: 1st 2 c.c. effluent	0.4	0.5	1.9	1.8	0.1	0.2
2nd 2-c.c. effluent	4.5	4.8	0	0	1.4	1.6
3rd 2-c.c. effluent	1.4	1.0	0	0	0.4	0.3
4th 2-c.c. effluent	0.3	0.4	0	0	0.1	0.1
5th 2-c.c. effluent	0.1	0.2	0	0	0	0.1
1st 10-c.c. effluent					2.0	2.3
Total active H_2O recovered					6.4	6.6
Core after 1000 c.c. H_2O flood	0.1	0.3			0	0.1

[a] The residual active water saturation (about 35 per cent) of these and subsequent cores is recognized as being somewhat higher than that normally observed for rocks of 200 to 250 md. This is believed, however, to be characteristic of this particular sandstone, since connate water saturations for this material as determined by capillary pressure measurements (made by Mr. H. G. Botset) were also high to approximately the same extent. It is believed, moreover, that the relative saturation has little or nothing to do with the interpretation of the results. In fact, an experiment was later performed with a core containing a quantity of water approximately equal to 20 per cent of the pore volume. As before, practically all of the tracer water was removed with the first portions of the effluent.

In the first attempt to follow the progress of the tracer as the active fluid was being displaced by the flooding water, the experimental procedure was again a duplication of the previous tests. The curves of Fig. 3 show the results obtained.

In the next experiment the process was varied, in that after active water had been pushed out with oil, 2 c.c. of oil was produced by gas drive. Inactive water-flooding then followed as before. The location of the radioactive material at different stages of the experiment is indicated by the curves of Fig. 4. The two curves showing the active water distribution for the saturated core represent repeat measurements. Part of the difference is instrumental, a part statistical, and part may be due to local changes in liquid distribution within the core.

To a first approximation, corrections were made on the curves of Fig. 4 for failure to limit the gamma-ray beam to the ¼-in. slot in the lead shield. The method followed was empirical, and involved measuring the activity due to a thin slice of core saturated with radioactive water when it was in various positions originally occupied by the experimental core. Contributions by the core when beyond the collimating slit could thus be summed up, and subtracted from the curves first obtained. The final result is a proportional reduction, with the exception of the ends, in ordinates of all the curves. Rather than make the corrections in Fig. 3, the end points were merely deleted. Obviously, this procedure has no effect whatever on the physical significance of the final results.

The experiments represented by Figs. 3 and 4 were performed under conditions that differed only in that a gas drive was employed in the latter prior to water-flooding to simulate reservoir conditions as they may exist in depleted formations. Nevertheless, the behavior with respect to connate water was the same in both instances. In neither case was active water pushed ahead of the driving fluid with a sharp and well-defined front, although, as discussed here-after, the resultant displacement efficiency was still remarkably high.

Unfortunately, the core giving the data shown in Fig. 4 was not scanned for activity following the initiation of oil-flooding until about 1.3 c.c. of active water had been collected (curve 3). Even at this stage, however, the activity at the outflow end was somewhat higher than had previously been found for the saturated core. This

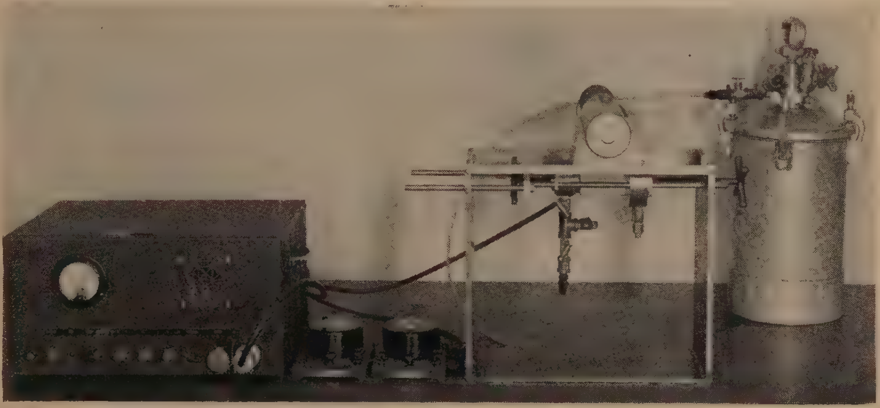

FIG. 2.—MOVABLE CORE HOLDER AND GEIGER COUNTER ASSEMBLY.

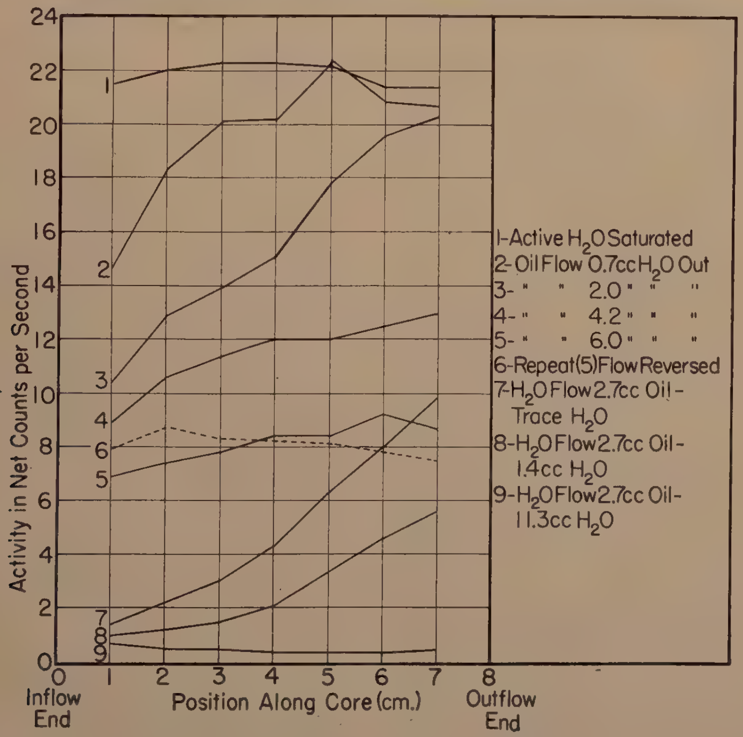

FIG. 3.—VARIATION OF RADIOACTIVITY ALONG CORE AT VARIOUS STAGES OF OIL AND WATER-FLOODING.

Core length, 8.4 cm.; volume, 51 c.c.; active H_2O to saturate, 10.6 c.c.; permeability (air), 200 md.

indicates that liquid probably had been lost at the ends during the process of removing the core and determining its over-all initial activity outside the holder. The high inflow concentration gradient, as illustrated by curve 3, was of relatively short duration. Already under the condition obtaining in curve 4, oil was by-passing water at the input end of the core and removing water mainly near the outflow end. The permeability to oil in comparison with water even at relatively high water saturation was such that large pressure differentials (~100 lb. per sq. in.) had to be applied to reduce the water saturation to the values indicated by curve 5. The sixth curve shows that no appreciable change in water distribution inside the core resulted during the production of oil by gas drive.

A high gradient in active water concentration was again established upon the application of the inactive water drive (curve 7). Actually, at this stage only the distribution of activity had been altered, as only an insignificant amount of active water had been removed. The remaining curves show in a semiquantitative manner the distribution of active water during the remainder of the water-flooding process.

The activities of the effluents were measured for the experiment of Fig. 3. The results are given in Table 2.*

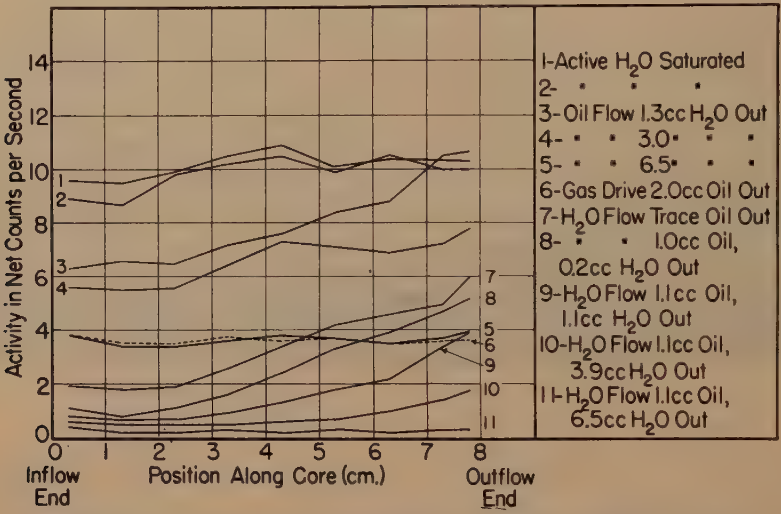

FIG. 4.—VARIATION OF RADIOACTIVITY ALONG CORE AT VARIOUS STAGES OF OIL AND WATER-FLOODING, CORRECTED FOR END EFFECTS ON ACTIVITY MEASUREMENTS.

Core length, 8.6 cm.; volume, 51.6 c.c.; active H_2O to saturate, 11.2 c.c.; permeability to air, 210 md.

From these measurements and the distribution curves of Figs. 3 and 4, the over-all efficiency of the connate water displacement is evident. Thus the measurements of Table 2 indicate that 77 per cent of the original connate water had been displaced after a water outflow of only 51 per cent of the pore volume. And from comparison of curves 11 and 6 in Fig. 4, it follows that 90 per cent replacement is achieved after a total outflow equal to only 68 per cent of the pore volume. These results indicate an even higher degree of displacement efficiency than the previous experiment.

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* While the residual oil saturations implied by the data of Tables 1 and 2 after water-flooding are higher than usually is found in sandstones, they are of the same magnitude as obtained in independent conventional flooding tests on Nichols Buff cores.

It is well known that end effects due to capillarity may play an appreciable role in the flow of oil and water through cores. In order to see whether similar results are obtained when at least the differential capillary effects between water and oil are eliminated, additional tests were made in which a core saturated with active water was subjected to flooding with dead water without the intermediate stage of oil flow. The results of this experiment are given in Table 3. The effluent was again collected in 2 c.c. portions.

TABLE 2.—*Activities of Effluents*

Core volume, c.c. 51
Air permeability, md. 200
Pore volume, c.c. 10.6
Active water (2 c.c. aliquot) 30.7 counts per second

Operation	Volume of Expelled Fluid, C.C.	Analysis of Expelled Fluid	
		Counts per Second	Active H_2O, C.C.
Oil flood..........	6.2 H_2O		6.2
Dead H_2O flood..	2.1 oil	0	0
Dead H_2O flood..	0.6 oil + 1.4 H_2O	20.4	1.4
Dead H_2O flood..	2.0 H_2O	19.8	1.3
Dead H_2O flood..	2.0 H_2O	10.6	0.7
Dead H_2O flood..	2.0 H_2O	4.2	0.3
Dead H_2O flood..	2.0 H_2O	2.1	0.1
Dead H_2O flood..	2.0 H_2O	1.1	0.1
Total recovered by dead H_2O flood..			3.9
Total active H_2O recovered.........			10.1

TABLE 3.—*Results of Flooding a Core with Dead Water*

Core volume, c.c. 31
Air permeability, md. 200
Porosity, per cent................ 21

Sample	Active H_2O Content, C.C.
Core saturated with active H_2O.........	6.6
Dead H_2O flood:	
1st 2-c.c. effluent..................	2.0
2nd 2-c.c. effluent..................	2.0
3rd 2-c.c. effluent..................	1.5
4th 2-c.c. effluent..................	0.6
5th 2-c.c. effluent..................	0.2
Total active H_2O recovered from core....	6.3
Core................................	0.2

Here, too, practically all the original water content was displaced by inflowing water. The radioactivity measurements indicated that 6.3 c.c. out of a total of 6.6 c.c. of water required to saturate the core were removed in the first 10 c.c. of water collected. And in a throughput of one pore volume, about 85 per cent of the original water content was replaced. This over-all displacement efficiency seems somewhat lower than that found with the flooding of oil-saturated cores. However, the differences may not be significant in view of the inherent variations between individual repeat experiments. If real, it might be explained as arising from the blocking action of the oil, in the oil-containing cores, against the flow of the invading water through the central parts of the pores, thus forcing the water to drive more effectively against the connate water. On the other hand, it is doubtful whether a strict comparison of the two types of experiment is inherently appropriate, since the initial interstitial water contents in the two cores are different. Thus, if the ratio of throughput volume for 90 per cent displacement to initial water content be used as an efficiency measure, the flooding of the oil-free core would appear to be more efficient than flooding cores containing both oil and water. In any case, it appears that the differential capillary effects between the oil and water do not play a predominating role in the experiments described above.

Finally, in order to obtain a further check on the radioactive tracer as an indicator, the first experiment was essentially repeated, using NaCl as a chemical tracer. The core was first saturated with a salt solution, approximately 0.3 normal. This procedure was followed by oil-flooding, and this in turn by a distilled-water drive. The effluent was collected in small portions and analyzed by titration with $AgNO_3$, using K_2CrO_4 as an indicator. The results are shown in Table 4.

Again the displacement efficiency was remarkably high. The results indicate that, for practical purposes, all the salt water was removed in a quantity of effluent equal to one pore volume.

TABLE 4.—*Experiment with* NaCl *as Tracer.*

Core volume, c.c. 37
Air permeability, md. 210
Salt H_2O to saturate, c.c. 7.5

Solution	Quantity of Effluent (c.c.)	Quantity of Tracer H_2O (c.c.)
Pushed out by oil	4.6–5.0	4.6–5.0
H_2O drive:		
1st H_2O throughput	2.0	1.7
2nd H_2O throughput	1.8	0.6
3rd H_2O throughput	2.1	0.2
4th H_2O throughput	2.5	0.1
5th H_2O throughput	2.0	0.1
6th H_2O throughput	1.8	0.0
7th H_2O throughput	1.8	0.0
Total		7.3–7.7

DISCUSSION AND CONCLUSIONS

Before considering the practical significance of the experiments described it is to be noted that there are two possible explanations for the apparent mobility of the interstitial water when subjected to waterflooding. One is a physical displacement and the other is that a transfer of the radiovanadium within the core from the active water to the inactive flooding water. To quantitatively evaluate the contributions of either mechanism would require the use of a tracer that is chemically identical with the main body of the connate water and could not separate from it by diffusion or solution processes. For this purpose heavy water could be used as the connate water, and its concentration could be determined in the effluent.

While the transfer mechanism cannot be definitely excluded without such independent tests, it is felt that it has not played a major role in the present experiments. Such transfer, if it occurs, must take place by a process of molecular diffusion, and rough calculations indicate that more time would be required for diffusion than was available during the flow tests. And even if it did occur, the maximum tracer concentration developed in the water that was initially inactive would equal half the concentration in the original active water when equal volumes were placed in contact. In Table 1, for core 1, the first 2.1 c.c. water effluent had a total activity corresponding to a content of 1.5 c.c. of active water. This is equivalent to a tracer concentration in the effluent 71 per cent of that in the original active water. During this phase of the experiment, 4 c.c. inactive water was forced into the core. It is reasonable to assume that the average amount of inactive water in contact with the connate water during the period was at least equal to the 2.4 c.c. of connate water. Hence, even if diffusion were complete, the maximum activity concentration in the effluent would be 50 per cent if none of the original connate water were displaced. In core 2, the average tracer concentration in the effluent during the first 4 c.c. inflow was 82 per cent, making a still greater discrepancy with that to be expected if solution transfer alone were the explanation.

The implication of these considerations is that while the absence of diffusion cannot be proved, the data do show that there must be an appreciable contribution of actual displacement of the connate water. At the same time the data are consistent with the hypothesis that all the observed effluent activity was due to a real displacement of the connate water, and there are no observations definitely requiring that the transfer mechanism be involved. Accordingly, until evidence to the contrary appears, it will be considered henceforth that the transfer mechanism has not been an important factor in the experiments described here, and it will be assumed, in effect, that it may simply be ignored.

Within the experimental errors, and neglecting any role played by the transfer mechanism, the mobility of the connate water under water-flooding action appears to be the same whether or not oil is in the rock, and regardless of the complete saturation of the core. In all cases 80 to 90 per cent of the initial water content is removed by flowing through the cores a quantity of extraneous water equivalent to a single pore volume.

This basic result has a number of implications. In water-flooding, the injected water will advance more slowly than would be anticipated, on the assumption that the interstitial water remains immobile. At the same time, as has already been noted from field experience, the first water produced from the output wells should be saline and represent the displaced connate water. Hence, the show of water in the producing wells will not in itself indicate a breakthrough or channeling from the injection wells, unless an analysis of its character proves this to be true. In fact, even without channeling, an appreciable period of wet-oil production may be anticipated simply while the interstitial water is being pushed ahead by the injected water. As mentioned in the introduction, such saline water cuts have often been observed, although quantitative data on the subject are very meager.

Other implications of the experiments reported here, assuming again that they were not merely the result of tracer transfer, pertain to the interpretation of fluid-content determinations in core analysis. For it has hitherto been almost universally assumed* that the total free core water measured in core analyses is the sum of all the initial connate water content plus that entering from the drilling fluid. Thus, the formation water saturation equivalent to the chloride content of the core is often taken as representing the total initial connate water content. And when tracers are used in the mud, the equivalent drilling fluid content of the core is determined, the residual left from the total water content again being taken as the true connate water saturation. However, both these procedures will lead to abnormally low connate water contents, on the basis of these results, if there is considerable invasion of drilling fluid. In particular, if the drilling-fluid intrusion only suffices to displace a single pore volume, the connate water should still be reduced to less than one third of its initial saturation.

Now from connate water determinations using oil-base muds it would appear that even when using tracers in water-base fluids, or by determining the chloride content, at least the right order of magnitude of connate water saturation is generally obtained. It may therefore be inferred that perhaps drilling-fluid contamination is not as common or extensive as generally supposed. In this connection it may be pointed out that core analysts have often noted that the contamination is less marked along the centers of large cores, and therefore they deliberately choose samples for fluid-content determination from the central region. It has also been observed that drilling-mud invasion is less in rapid than in slow coring. And, of course, in cable-tool or dry coring, the tendency for contamination is inherently minimized. Moreover, tests made with tracer-containing aqueous muds show residual drilling-fluid contents only of the order of 15 to 20 per cent. Apparently this is often enough to reduce the oil saturation to the order of that expected from continued water-flooding operations, although it may not succeed in displacing much of the connate water. On the other hand, when such drilling-fluid invasion does occur, the residual connate water will at best represent only a possible minimum of the initial interstitial water. In any case, it would appear that if the evidence of connate water mobility presented here has any validity, a strong argument is provided for coring with oil or oil-base mud. It has been generally recognized that coring with oil is the *simplest* means for determining connate water, as the need for chloride analysis or direct use of a tracer is thus eliminated. But the present experiments show that even with the use of tracers in water-base muds the results may be uncertain, and the only safe procedure when using methods involving the fluid saturation of the core prior to extraction is to use oil or an oil-base mud as the coring fluid,* provided its disadvantages in other respects do not make its use otherwise impractical.

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* The possibility of connate water displacement during coring has occasionally been mentioned in the literature.[3] However, nothing quantitative about it has appeared thus far. In a paper published by Penn State Mineral Industries Expt. Station,[4] core analyses are reported showing abnormally low connate-water saturations (Table 1), which presumably were the result of flood and drilling-water invasion. While the possibility of such displacement is mentioned in this paper, no conclusion is drawn that it has actually taken place.

Since the paper was written the attention of the authors has been called to a report by W. S. Walls [Drill. and Prod. Practice, Amer. Petr. Inst. (1941) 178] of experiments similar to those recorded in Table 4, with results in substantial agreement to those presented here. It may also be mentioned that distribution curves equivalent to those of Figs. 3 and 4 have been obtained by motor-driven continuous scanning of the core and a pen recording of the γ-ray counting rate.

Finally, the possibility of connate water displacement by invading aqueous media may have a bearing on the interpretation of electrical logs. If excessive penetration of the logging fluid into the formations should occur, the removal of the interstitial waters from the vicinity of the well bore will lead to apparently high values of the resistivity and uncertainty in the interpretation of the records. The self-potential log may also be affected by changes in the nature of the fluid surrounding the well bore.

ACKNOWLEDGMENTS

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DISCUSSION

H. J. WELGE.*—The method of following the displacement of fluids by means of radioactive tracers in solution is a valuable tool in research on cores. One or two suggestions, however, on the paper seem pertinent.

First, the authors draw the important conclusion that the connate brine apparently possesses surprising mobility under the influence of water encroachment. It is desired to point out, however, that the rates of water-flushing used were quite high compared with rise in a water table, edge-water encroachment, or even water-flooding as carried out in field practice. Specifically, with cores of about 200 md. permeability and subject to the pressure differential imposed in the experiments of 10 lb. per sq. in., the rate of advance of the water-flood may be calculated to be of the order of 15 cm. per min., or 260,000 ft. (52 miles) per year. Although this rate of advance is not sufficient to cause turbulent flow in the pores, the phenomena of turbulent and linear flow of liquids have been studied largely in straight tubes, not in tortuous capillaries. It seems possible, therefore, that the fluid conditions in tortuous pores, while yet apparently in the region of linear flow, may be a function of the rate of fluid flow. In particular, it would appear possible that an increasing amount of whirling and cavitating action would act on the connate fluid as the velocity of the flow is increased.

Accordingly, the conclusions on the mobility of connate brine might be directly applicable to conditions obtained in a core during drilling, for example. In connection with extending the conclusion, however, to include conditions in a field during water-flooding, it might be desirable to make some experiments at reduced rates of flow.

Second, the statement is made that the phenomenon of transfer of connate brine by diffusion could be studied apart from displacement, if heavy water were used as the connate water. It is difficult to understand how this technique could aid in the study, inasmuch as deuterium oxide, by reason of the usual thermal energy of translation, could and does diffuse into ordinary water in a manner similar to the tracers actually used, as well as any substances that could conceivably be used by reason of their miscibility with water.

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* The inherent lack of mobility of connate water during normal clean oil production indicates that there is little likelihood of connate water displacement by invasion of oil when coring with oil. On the other hand, in depleted formations the invasion of the coring oil will still leave uncertain the value of the oil saturation.

* The Carter Oil Co., Tulsa, Oklahoma.

M. Muskat (authors' reply).—Dr. Welge's comments are well taken. It is true that if the flow conditions in the reported experiments were turbulent, direct mixing and displacement of the connate water would be expected, even though under viscous flow such displacement might not take place. However, it is felt that even under the high pressure gradients used in the experiments the flow was definitely viscous. Many early, as well as recent, experiments have shown that the flow through a porous medium will be viscous up to Reynolds' numbers of the order of 1. In the experiments in question it took about 10 min. for a through-flow of 2 c.c. Assuming an average grain diameter of the order of 0.1 mm., the Reynolds' number is found to be less than 0.001, which would certainly ensure viscous flow. And even for Dr. Welge's calculated flow rate of 15 cm. per min , the Reynolds' number would still be much less than one, taking into account the factor of 4 to 5 required to translate linear rate of advance into equivalent flux velocity. Of course, the reason the actual rates of flow were not as great as estimated by Dr. Welge is that the effective permeability to water during the flooding experiments was much lower than the air permeability of 200 millidarcys.

It is true that deuterium oxide would be subject to diffusion and could not uniquely settle the question whether diffusion or mass displacement controlled the experimental results. The use of heavy water, however, was suggested mainly as a possibility wherein the magnitude of the diffusion might be more readily estimated, and because the experiments would not be affected by radioactive decay, as occurs in a radioactive tracer. On the other hand, the practical difficulty of using a mass spectrometric technique for determining the concentration of the heavy water in the effluent would make such experimentation rather impractical, and the authors themselves did not intend to pursue this possibility further at the present time.

J. F. Kendrick*—It is possible to set up another concept of connate water. This can be visualized easily, if one will picture a tile of variegated marble, such as Verde antique. The percentage area of the white portions of such a tile should equal the percentage connate water saturation, and the percentage area of the green portions should equal the percentage oil saturation. In this way, we could have two separate systems, the white area being composed of pores too small for the prototype of the oil to enter when it was concentrated in the reservoir.

All theories of the migration of the prototype of crude oil seem to end with a globule of that prototype surrounded by an envelope of water. During the millions of years that followed, the molecules slugged it out, and it is not hard to assume that the molecules of the prototype won out, eventually, by blasting the water molecules off the surface of the sand and taking their places. This results in a concept of an oil-wet sand, and it is interesting that a number of people believe the Wilcox sand of Oklahoma City to be oil-wet, and out this way, one hears occasional references to the oil-wet Bradford sand. If one sand is oil-wet, why shouldn't all oil sands be oil-wet? Under such a theory, a 100 pct gas reservoir would have dry sand in those parts in contact with the gas, the original connate water accounting for at least part of the moisture content of the gas.

One can make up quite a list of "undoctored incidents that actually occurred":—the breakdown pressure in squeezing and acidizing; gravitational separation; the apparent high percentage of recovery from water-drive fields; "break-through" or "channeling" in artificial water drives; wells that have produced pipe-line oil after air or gas has been injected into them for varying lengths of time; the salt content of crude oil, etc. Does such a theory account for such "incidents" more satisfactorily than the generally accepted theory?

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Extending the Application of Electric Analogy in Oil-reservoir Studies

By Henry Schaefer*

(Galveston Meeting, October 1946)

Abstract

Solution by electric analogy of performance problems of reservoirs containing oil and gas has heretofore depended upon a process of successive approximations based on material-balance calculations, because of variation in fluid compressibility. By the addition or subtraction of electric condenser capacity, the analogy network can be adjusted automatically for changing compressibility due to evolution of gas in the reservoir. The addition of a condenser is accomplished by an electronic circuit, which is described; subtracting a condenser is done by merely opening the electrical circuit by means of a relay.

Introduction

V. Paschkis and H. D. Baker[1] first developed in this country a method of applying the analogy of flow of electric current in noninductive circuits to solution of heat-flow problems and suggested its application for certain other problems, such as flow of fluids or mass transfer and chemical diffusion. Necessary details for applying the analogy to flow of fluids in porous media were developed by W. A. Bruce;[2] he classified[3] the types of analysis and predictions that can be made by the analogy in class 1, when the reservoir contains oil but no gas for the period under consideration; in Class 2, when both oil and gas exist in the free state in the reservoir sometime during the period under consideration.

Duplication of bottom-hole pressure history and predictions for class 1 reservoirs can be obtained directly by electric analogy. Until now, the solution of problems pertaining to reservoirs in class 2 was obtained by successive approximations along with material-balance calculations. The object of this paper is to present a method for simplifying the application of electric analogy to class 2 reservoirs, resulting in a solution of these problems as direct as is possible for class 1 reservoirs. This is accomplished by an electronic control circuit, which adjusts the analogy network for changing compressibilities of fluids contained in the reservoirs.

Analogy Network

In electrical phenomena the analogy to two-dimensional fluid flow in a porous media is that of current flow through an ideal conducting sheet. This sheet, perfectly insulated on both sides, has resistance and capacitance uniformly distributed throughout its area but is of negligible inductance. The need for having the surface boundaries perfectly insulated is that good correspondence may be had with a permeable fluid-conducting stratum bounded above and below by impermeable media. In actual application the ideal conducting sheet, which has distributed parameters, is replaced by a network having lumped values of resistance and capacitance—the resistances are series elements and the capacitances are shunt elements. The larger the number of lumped

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* Stanolind Oil and Gas Co., Tulsa, Oklahoma.

[1] References are at the end of the paper.

elements, the more perfect will be the approximation to the ideal conducting sheet by the network. In setting up the network for reservoir analogy, a feasible compromise in the number of elements is usually possible. It has been shown that electric current corresponds to fluid flow rate, electrical potential corresponds to fluid pressure, electrical resistance corresponds to fluid flow resistance of the porous media, and electrical capacitance corresponds to the product of interstitial fluid times its compressibility.[2]

Calculation of Electrical Values

The first step in the calculation of electrical values for the analogy network is the division of the reservoir into "lumps" or blocks, preferably regular in shape, to simplify calculations, but enclosing volumes of nearly equal pressure, neglecting gravity. It is generally convenient to start in the oil-saturated section with the dividing lines following lease lines wherever possible. The number of blocks in the oil section is limited by apparatus design, since the production from each block must be controlled by individual circuits. From the oil section, the dividing lines are then extended out into the water section, terminating at impermeable boundaries or outcrops; the total number of blocks is limited only by the number of condensers and resistors available in the apparatus. In the outer regions of the water section, it is generally feasible to increase the size of the blocks, since the only requirement is that the pressure gradient across each be comparatively small.

Next, the volume of interstitial fluid multiplied by the applicable compressibility constant is calculated for each block. The value of this product, which will be designated as "compressibility function," is converted into the corresponding amount of condenser capacitance by a scale factor.

Finally, the resistance to fluid flow is calculated on the assumption that the fluid flows from the center line of one block to the center line of the neighboring block. Values of the resistance to fluid flow are converted into corresponding units of electrical resistance by a scale factor.

Assembling Network

The electrical network is assembled by connecting one terminal of the condenser that represents a block of porous media through the associated resistors, with one terminal of each of the neighboring condensers. The other terminal of each condenser is connected to a common ground. A current of constant voltage is then applied to the network, charging the condensers until all have reached the applied voltage, at which time the network is in equilibrium.

By means of a sliding switch with sawtooth contacts and suitable electronic control circuits, current is drained from the points in the network that correspond to blocks of the oil-saturated section in accordance with the production history of the field. Change in potential at a point of interest in the network is recorded by an oscillograph operating in a high-impedance electronic voltmeter circuit and the resulting curve when interpreted in reservoir units shows the change in bottom-hole pressure for the corresponding point in the porous media.

As long as the compressibility function for a block remains constant, its value can be represented by a fixed amount of electrical condenser capacity. However, for reservoirs in class 2 this product will not remain constant even though the pore volume occupied by fluid is fixed, since from Boyle's law the compressibility of a gas varies inversely with the pressure. Bruce has developed the equation that governs the current supplied by the analogy to represent compressibility of gas;[2] however, to follow this equality exactly would require complicated electronic controls. Another method of adjusting for gas compressibility is to add or subtract condenser capacity. If this is done with a continuously variable condenser, complex controls would be required for adjustment in accordance with a predetermined plan. A reasonable approach to the problem is to change condenser capacity in steps, which can be performed by adding or subtracting fixed condensers at appropriate time intervals.

Electronic Control Circuit

To subtract a condenser is no problem, since it merely requires that the circuit to the condenser be opened electrically, which is easily accomplished by a relay. To add a condenser is not so simple, unfortunately, since the potential of the condenser must be equal to the potential of the point of the electrical network at which it is to be added. Furthermore, it is not desirable to draw current from the network to operate a suitable discharge circuit for the new condenser.

An electronic circuit that has high input impedance for the signal but contains a point that follows the signal potential and with comparatively low impedance to ground is shown in Fig 1. Two pentode tubes are used, connected in series, one acting as a cathode follower and the second controlling the plate current of the first.

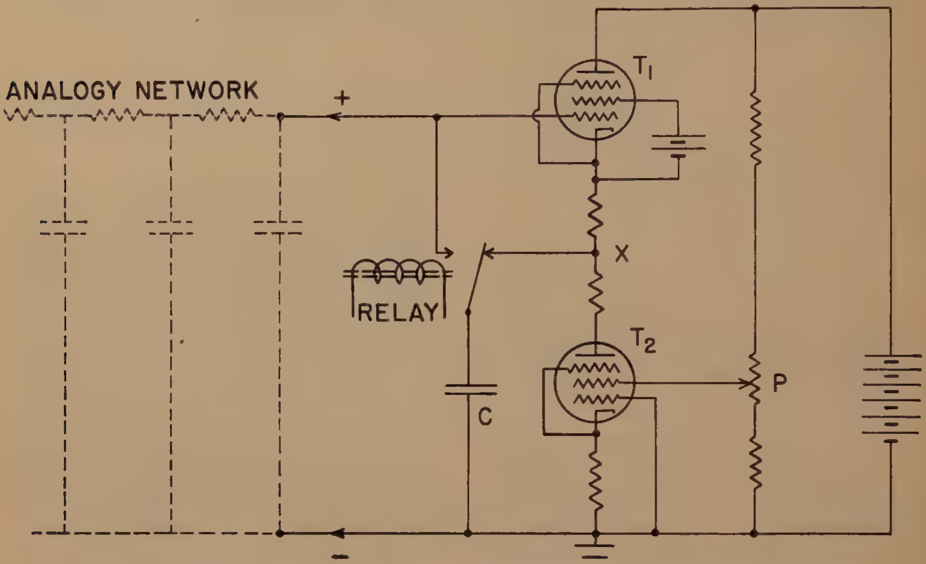

Fig 1—Control circuit for adding condensers to analogy network.

In Fig 1 the control grid of T_1 is connected to the point of the analogy network where condenser capacity change is to occur in accordance with change of reservoir fluid compressibility. As long as the plate voltage of T_1 exceeds the grid potential plus voltage drop across the tube, the grid will be negative with respect to the cathode and grid current will be 10^{-9} amp or less, depending on the type of tube. This signal current for controlling the discharge of the new condenser, *C*, is negligible when compared with production current, which exceeds 10^{-6} ampere.

Curves for plate voltage vs. plate current of radio receiving-type pentodes show that the plate voltage has relatively little effect on plate current. This characteristic is used as a control for the plate current of T_1, which causes the grid bias voltage of T_1 to remain constant. Thus, there will be a point such as *X* on a voltage divider between the cathode of T_1 and plate of T_2, which will be at the same potential as the grid of the former tube. By connecting X to one contact of a double-throw relay as shown by Fig 1, the potential of a new condenser such as C will be equal to and follow the change of potential of the grid of T_1, which is connected to the analogy network at a point representing the reservoir.

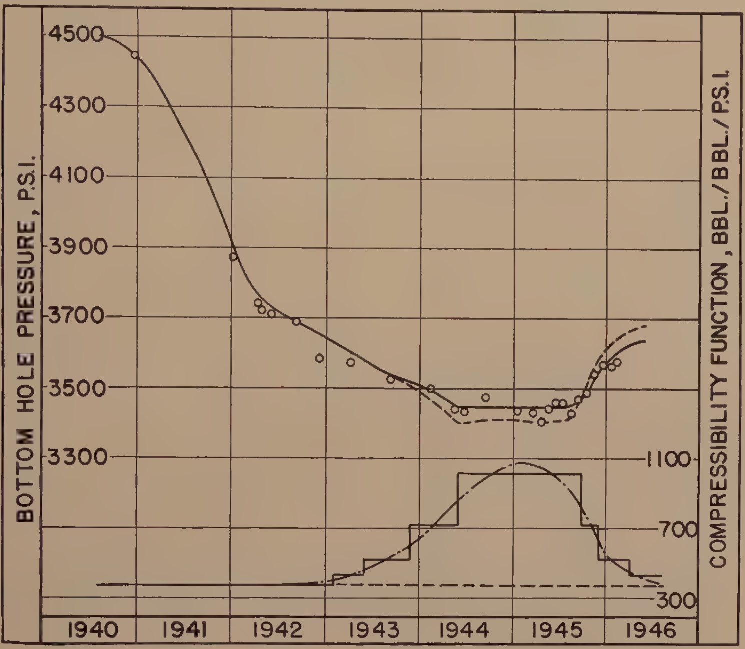

FIG 2—PERFORMANCE OF WEST HACKBERRY "D" SAND.

Circled points are measured field pressure. Solid pressure curve from electric analogy with changing compressibility function per step curve. Dotted pressure curve from constant compressibility function. Dot and dash curve is obtained from calculated values.

At the correct instant when the fluid compressibility increases an amount equal to the condenser capacity C, the relay is tripped, thus adding C to the analogy network. As many additional condensers can be added as there are electric relays but a separate electronic circuit is necessary for each point of the network.

RESULTS

Fig 2 shows the pressure history of the West Hackberry "D" sand field in Southern Louisiana. This sand contained crude that was initially undersaturated, but, as pressure declined, gas evolved from solution, causing an increase in compressibility of reservoir fluids. Pressures obtained from field surveys are indicated by the circled points, the solid curve was obtained by electric analogy with adjustment for fluid compressibility variations, and the dotted line from electric analogy without compressibility correction. The dot-dash curve shows fluid compressibility as calculated by material balance, and the step curve show compressibility values used in the analogy. Incidentally, the increase in reservoir pressure beginning March 1945 is due to a water repressuring program.

Fig 3 shows the pressure history of the 5000-ft sand at the Luby field, in South Texas, which contains crude that was saturated with gas at original reservoir pressure. As before, circled points are field

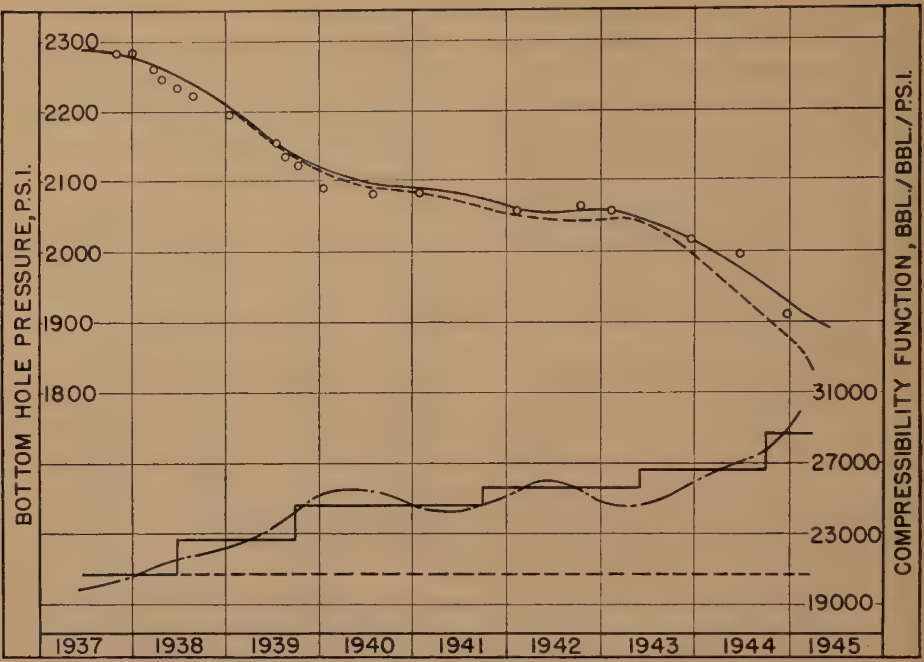

FIG 3—PERFORMANCE OF LUBY FIELD 5000-FT. SAND.

Circled points are measured field pressure. Solid pressure curve from electric analogy with changing compressibility function per step curve; dotted pressure curve from electric analogy with constant compressibility function. Dot and dash curve is obtained from calculated values.

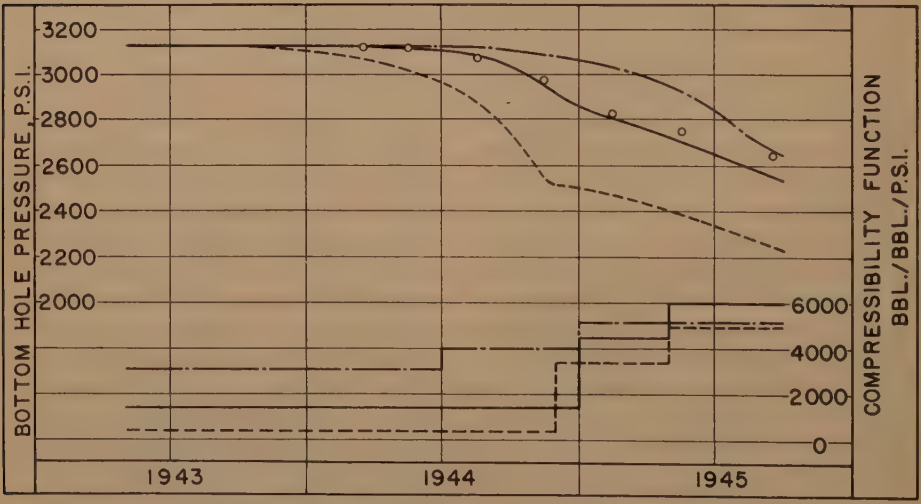

FIG 4—PERFORMANCE OF PART OF WEST EDMOND FIELD.

Circled points are average measured pressures. Upper three curves are from electric analogy with changing compressibility function as shown by corresponding lower curves.

survey pressures, the solid and dotted curves were obtained by electric analogy with and without fluid-compressibility corrections, and the fluid compressibility from material-balance calculations is shown as a dot-dash line with analogy compressibility shown by the step curve.

The pressure gradient across both of these fields was small; consequently, suitable results were obtained from the electric analyses by using one block for the oil and gas section.

West Edmond is an example of a field in which the pressure gradient is too large and the field too complex for representation by a single block. For this study the field was divided into nine blocks containing all of the known producing area. For purpose of illustration the curves for one of the nine blocks is shown in Fig 4. Three electric analysis curves are indicated, two of them based on compressibility values obtained from material-balance calculations and the third by trial and error adjustment of compressibility. Circled points are actual field pressures.

CONCLUSIONS

Duplications of past and prediction of future bottom-hole pressure changes in reservoirs containing gas can be obtained by electric analogy without material-balance calculations. A circuit is presented for automatically connecting into the network condensers charged to the correct potential at the moment the connection is made.

ACKNOWLEDGMENT

The author is grateful to the management of Stanolind Oil and Gas Co. for permission to present this paper, and desires to recognize the assistance given to him by Messrs. J. B. Clark and Frank Nuss, and especially by Dr. S. S. West, who suggested the basic electronic circuit.

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DISCUSSION

(*John Murrell presiding*)

H. W. Ritchey.*—The method of adding capacitance to the network to account for variable compressibility is indeed a valuable contribution for extending the application of electric models for solution of problems involving flow of compressible fluid and for the solution of unsteady-state heat-transfer problems where the conducting medium has variable heat capacity.

The exposition, however, is rather brief, and a number of items might be expanded to advantage. For example, how is the time scale of the model correlated with the time scale of the reservoir, and what arrangements are made to regulate the drain or input of current to correspond with production or water injection of the oil reservoir? If the basic methods described in the references were used, a statement to such effect would clarify these points. In addition, the inclusion of more details such as the constants of the electronic circuits would increase the utility of the information and would be helpful to those interested or working along similar lines.

W. A. Bruce† and Irene Haskett.†—The writers feel that Mr. Schaefer has made a significant contribution to the field of electrical analogy reservoir studies by the development of this ingenious electronic circuit and agree that the expansion of the gas cap and the gas being released from solution can be accurately simulated by a gradually increasing electrical capacitance.

It is believed important to point out that the accuracy and scope of the device is dependent somewhat upon the number of elements, or individual gas-cap addition units provided. In the course of any problem in which the effective reservoir free-gas volume changes it will be necessary to change the electric capacitance to maintain the analogy of the analyzer. If the free-gas volume is changing about 2 pct per month and the problem is to be solved with the analyzer within an error of 2 pct, it will be necessary to provide for capacitance changes for each time period corresponding to a month. If it is desirable to follow such a problem for 5 years with this accuracy, 60 capacitance changes would be necessary. Actually it is unlikely that such frequent changes in capacitance would be needed, but it is possible that one-third, or 20 such changes, would be found necessary in the course of a study of a number of reservoir problems.

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From the circuit diagrams indicated by the author, the provision of 20 such units would mean providing a large and rather complex electronic switching device having 40 vacuum tubes and 20 relays, and would require a set of 20 banks of adjustable capacitors. The author does not state how many such units he used in the solution of the Hackberry problem, but inspection of Fig 2 indicates that probably he used between four and eight. This apparently was sufficient to make an accurate study of this problem; but it would be necessary to have a larger number of adjustable capacitor units in order to solve problems of greater complexity.

It might be useful to suggest another point in connection with this device. In making a study of a reservoir having an original gas cap, and for which there exists little information concerning the nature of the aquifer, the method of increasing pool capacitance becomes more complicated. The usual method in setting up such a problem involves changing the arbitrary proportionality factor that is used to relate the size of the aquifer zone condensers to the formation void volume of the selected aquifer zones. This is done without actually computing or estimating the fluid capacitance of the zones. The fluid volumes and compressibilities are determined in the study by the electrical constants with which the best fit between the analyzer curve for pressure and the observed field pressure curve is obtained. These electrical constants in turn will fix the size of the condensers used in the author's device. Hence the condensers will need to be adjusted every time a test is made in which new aquifer conditions are assumed.

HENRY SCHAEFER (author's reply).—Correlation between model and reservoir times is adequately explained in reference 2.

The drain of current to correspond with production rate can be regulated to a fair degree by a pentode radio-receiving tube operating in the region where plate current is nearly constant with changing plate voltage, the grid bias being varied with time in accordance with the producing rate. Closer regulation is obtained by using a resistor in the cathode circuit of the pentode. Still better control is obtained from a simple voltage-regulator circuit. Inversion of these control circuits will permit regulation of injection current. A detailed description of methods to control current is beyond the scope of the paper.

In reference to the criticism that a complex electronic switching device would be necessary, it is pointed out that only one electronic control circuit using two radio-type receiving tubes is required for each point of the analogy network where condenser capacity is to be changed for changing fluid expansibility. In studying the West Hackberry "D" sand two vacuum tubes and four relays were used. The Luby field study required two vacuum tubes and five relays. Nine control circuits for adding condensers to the analogy network, with six relays, were used for the West Edmond field study.

The inference that capacity change is required each time the gas volume changes by 2 pct in order to obtain an answer within an error of 2 pct is incorrect. Fig 2 shows a capacity increase of threefold causing less than 2 pct change in the pressure curve.

Estimating Interstitial Water by the Capillary Pressure Method

By O. F. Thornton* and D. L. Marshall,† Members AIME

(Galveston Meeting, October 1946)

ABSTRACT

RESULTS of the determination of the interstitial water content of several core samples from oil reservoirs are presented. Data obtained by the capillary pressure method, which has recently been developed, are compared with water saturations measured in cores cut with oil-base mud and with values calculated from the electrical resistivity of the formation. The agreement between the capillary pressure and other methods, combined with the fact that similar agreement has been obtained by others, indicates that the capillary method properly applied yields results sufficiently accurate for most engineering purposes. In some cases, it may be possible to extend the utility of data obtained with the capillary pressure method by correlation of interstitial water saturation with more easily measured physical properties of the media.

INTRODUCTION

Several methods are in use for determining or for estimating the interstitial water saturation at given points within oil and gas reservoirs. The direct measurement of the water content of cores obtained with nonaqueous fluid in the hole is believed to be an accurate method under most conditions. The water saturation may be calculated by use of the resistivity curves of the electric log,[1] although this method is not applicable under conditions that exist in some reservoirs. Recently, a method has been developed and described[3,7] wherein the interstitial water saturation of cores is measured at a capillary pressure such that conditions existing in the reservoir are simulated. The purpose of this paper is to present data obtained by use of this latter method, and to compare the results obtained with determinations made by other means.

METHOD

The theory underlying the capillary pressure method applied to petroleum reservoirs has been discussed adequately in the literature by Garrison,[2] Leverett,[5] and others.[3,6,7] Briefly, and simply, capillary pressure is defined as the difference in pressure between two contacting fluid phases, such as oil and water. For the simplified sand, water and oil system illustrated in Fig 1, the pressure difference can be stated as follows:[6]

$$P_c = \gamma \left(\frac{1}{r_1} + \frac{1}{r_2} \right) \qquad [1]$$

where P_c is the capillary pressure in pounds per square inch, γ is the interfacial tension between oil and water in pounds per inch, r_1 and r_2 are the radii of curvature of the interface between oil and water in inches.

Capillary pressure varies in a given reservoir with depth because of the greater density of the water phase as compared with oil or gas. The following equation expresses the difference in pressure between two points:

$$P_1 - P_2 = \frac{h\Delta\rho}{144} \qquad [2]$$

where $P_1 - P_2$ is the capillary pressure difference in pounds per square inch, h is

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[1] References are at the end of the paper.

the vertical distance between the points in feet, and $\Delta\rho$ is the difference in density between the water and oil or gas in pounds per cubic foot. If the capillary pressure at a given reference depth (such as the water level) in a reservoir is known, the pressure at any other depth can be computed from Eq. 2.

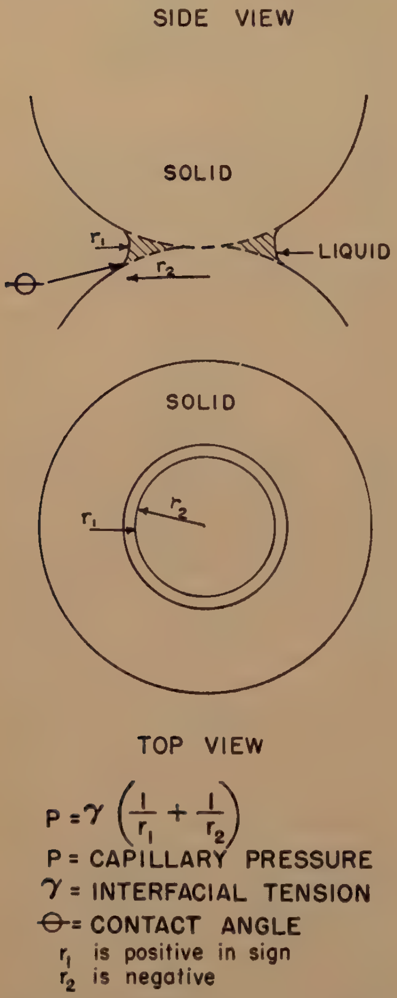

FIG 1—ILLUSTRATING CURVATURE OF WATER-GAS INTERFACE (*After M. C. Leverett*).

The capillary pressure method of measuring interstitial water content consists essentially of placing the core sample in the laboratory under the capillary pressure existing at the depth from which the core was obtained, as computed from Eq. 2. The capillary pressure for the laboratory fluid system which is equivalent to that for the reservoir fluids at reservoir conditions may be computed from Eq. 1, so that the water saturation of the core as it is believed to have existed in the reservoir can be obtained by direct measurement.

PROCEDURE

For the capillary pressure determinations described herein, core samples were selected from three wells in two Louisiana Gulf Coast reservoirs of Miocene age.

Well A, Fig 2, was drilled with conventional water-base mud to a depth of 8660 ft, where a string of 7-in. casing was set. The drilling fluid was then changed, and an oil-base mud was used in coring to the total depth of 8752 ft. The oil-base mud was replaced by the original mud before the hole was reamed so that the electric log obtained was comparable to that of other wells in the same reservoir. From representative samples of the cores recovered, determinations of water and oil saturations, salt content, porosity and permeability were made by conventional methods. Samples also were selected for capillary pressure determinations. Core samples also were obtained from two wells in another field. The cores were cut using water-base mud approximately three years prior to the capillary pressure determinations. The electric log of one of these wells designated as well B is shown in Fig 3.

The laboratory apparatus for the capillary runs was similar to that used by other investigators (Fig 4). It consisted of a metal cylinder, with a removable pressure tight cap through which pressure could be applied. The base of the cylinder was closed with a membrane which was permeable to water but impermeable to air at specified pressure differentials. Some of the membranes first used were made of a thin layer of hydrated Wyoming bentonite on oilite bearing metal. Later, porous porcelain plates with high displacement pressures were used.

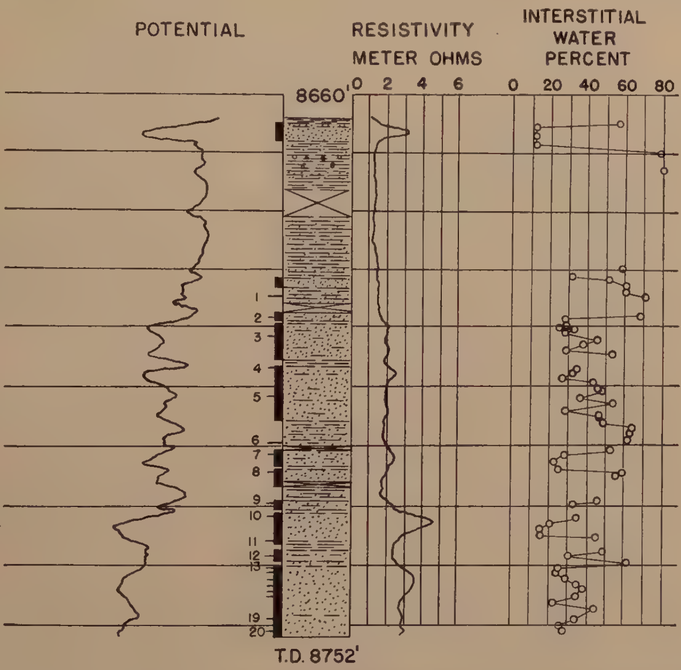

Fig 2—Log of well A, showing location of core samples (electrode spacing 16 inches).

Cores were cut to convenient size, extracted with carbon tetrachloride and acetone to remove oil, and dried to constant weight over anhydrous $CaSO_4$. The bulk volumes of the samples were measured, and the porosities were either determined with a gas-type porosimeter or assumed to be the same as those of duplicate samples previously analyzed. Some of the more friable samples were coated with cellulose acetate cement to prevent their crumbling.

The samples were saturated by placing them in water and by then applying a vacuum to the containing vessel. By this method, saturations of 80 to 90 pct of the porosity were obtained in a short time. It was found that water of sufficiently high ionic concentration to prevent hydration of clay particles should be used. Erratic results were obtained using a 5 pct sodium chloride solution, particularly with core samples containing large amounts of clay. In the measurements described herein, formation water that had been filtered to remove iron oxides and treated to kill bacteria was used with satisfactory results.

After the samples were saturated and weighed, they were placed on the membranes in the core holders and a constant air pressure was applied through the opening in the top cover. When equilibrium was signified by constant weight of the core sample, the water saturation of the core was computed by difference between the dry weight and the weight of the partially saturated core.

The water phase was continuous from the core through the semipermeable plate, and the pressure on that phase was that of the atmosphere. The pressure difference between the air and water phase, or the capillary pressure, was therefore equal to the gauge pressure of the air.

EXPERIMENTAL RESULTS

Shown in Fig 5 are typical results of a series of equilibrium water saturations at various capillary pressures. The curves are similar to the desorption loops of the pressure saturation curves obtained by others[3,5,7] consisting of a horizontal seat, a region of sharp curvature, and a vertical portion. The horizontal seat is approximately equivalent to the displacement pressure, below which pressure the core is saturated with water. In a reservoir, this may be thought of as the water level. For the vertical portion of the curve, very little change in saturation occurs for large changes in pressure, and an "irreducible." water saturation is approached. This corresponds to the productive zone of a reservoir. The region of sharp curvature corresponds to the transition in a reservoir from the water level to the oil or gas-producing zone.

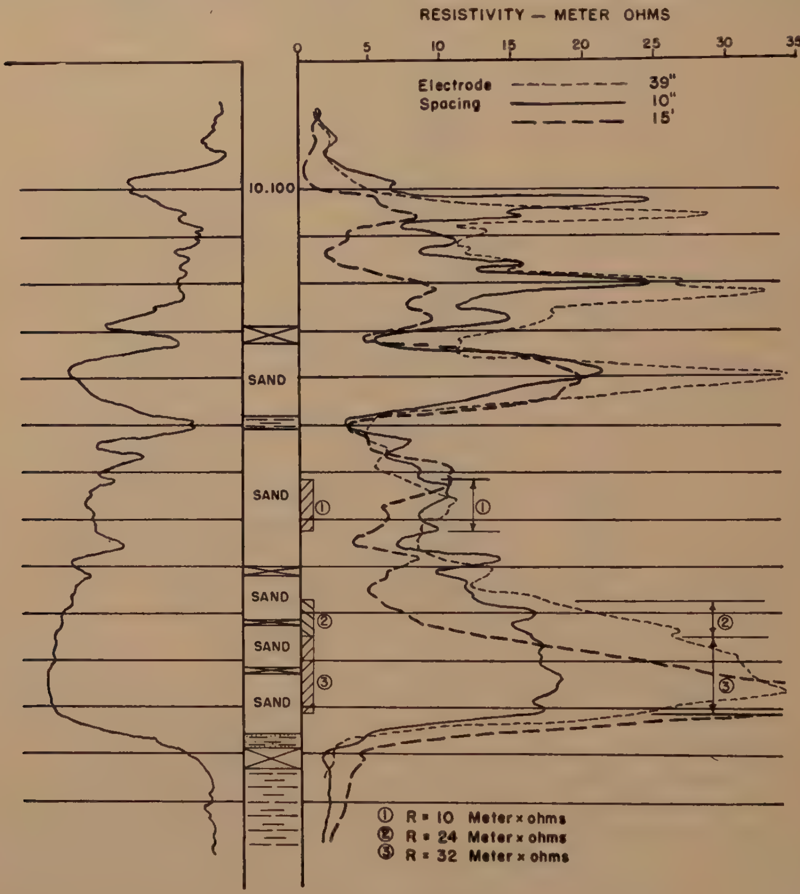

FIG 3—LOG OF WELL B.

Table 1 summarizes the results obtained from analyses of 20 samples from well A, taken at depths shown on Fig 2. The laboratory values of capillary pressure equivalent to the capillary pressures in the reservoir at the proper depths are shown. The capillary pressure at each depth was computed by means of Eq. 2, assuming the pressure at the water level of the reservoir (8773 ft) was equal to 1.5 psi. The densities of reservoir fluid and reservoir water were 31.8 and 67.4 lb per cu ft, respectively.

Since air was used rather than reservoir fluid in these experiments, it was necessary to compute the capillary pressure in the laboratory system which was equivalent to the "reservoir" capillary pressure. For this purpose it was assumed that the contact angle and radii of curvature were the same at a given water saturation for either the laboratory or reservoir fluid system. From Eq. 1, the correction factor by which the pressures computed as above from Eq. 2 should be multiplied is the ratio of the interfacial tensions of the two systems. From the data of Hocott,[4] this factor was estimated as two and two thirds.

Fig 5 shows that the capillary pressure values calculated as above correspond to the vertical portions of the curves, or practically to the "irreducible" water saturation. In other words, the cores were taken from a distance sufficiently far above the water level to be outside the transition zone.

Values are shown in Table 1 for the interstitial water saturation of each core obtained: (1) by retort distillation at above 400°F; (2) by calculation from the salt content (obtained by titration) of the core and known salinity of the reservoir water; and (3) by the capillary pressure method.

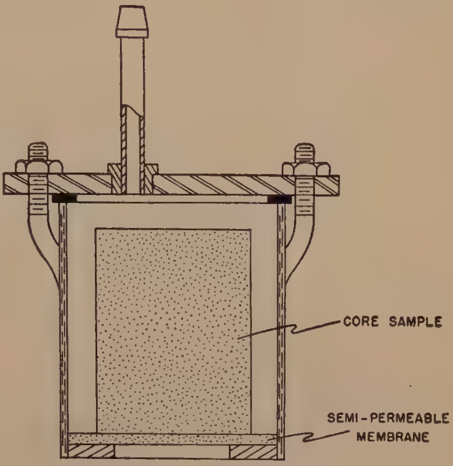

FIG 4—CORE HOLDER USED IN LABORATORY DETERMINATIONS.

The retort distillation values are higher than those obtained by the other two

TABLE 1.—*Water Saturation, Well A*

Sample No.	Permeability, Mds	Porosity, Pct	Distance Above Water Level, Ft	Laboratory Pressure, Psi	Interstitial Water Saturation, Pct of Porosity			
					(1) By Distillation	(2) From Salinity	(3) Capillary Method	(3) − (2) Difference
1	29	17.0	78	59	89	71	74	+3
2	312	29.3	74	56	28	23	23	0
3	382	22.3	70	53	52	37	37	0
4	518	28.1	66	50	29	34	33	−1
5	250	23.0	61	47	53	36	38	+2
6	63	16.0	54	41	73	61	61	0
7	2,556	27.2	51	39	36	28	28	0
8	23	20.0	48	37	82	59	59	0
9	319	25.7	43	33	44	32	27	−5
10	1,830	31.1	40	31	19	20	19	−1
11	550	27.1	37	29	47	44	40	−4
12	1,490	27.2	35	27	44	38	38	0
13	1,118	31.0	33	26	30	25	24	−1
14	1,730	32.6	32	25	27	23	24	+1
15	540	27.9	31	24	35	29	27	−2
16	1,048	28.6	30	24	36	34	25	−9
17	410	27.5	29	23	38	37	35	−2
18	1,960	27.4	28	23	33	34	34	0
19	2,238	29.8	24	20	36	34	26	−8
20	1,120	30.9	22	19	32	28	30	+2
	Average				43	36	35	−1.3

methods for some of the cores, but there is good agreement between the salinity and capillary methods. The higher values obtained by distillation probably are attributable to removal of bound water (called "water of crystallization"[8] by some investigators) caused by the high temperature attained in the retorts. This bound water contains no salt, while the "capillary" water salinity should be the same as that of bottom water. It is believed the salt content of these core samples is a more reliable index of the interstitial water saturation than the values obtained by retort distillation.

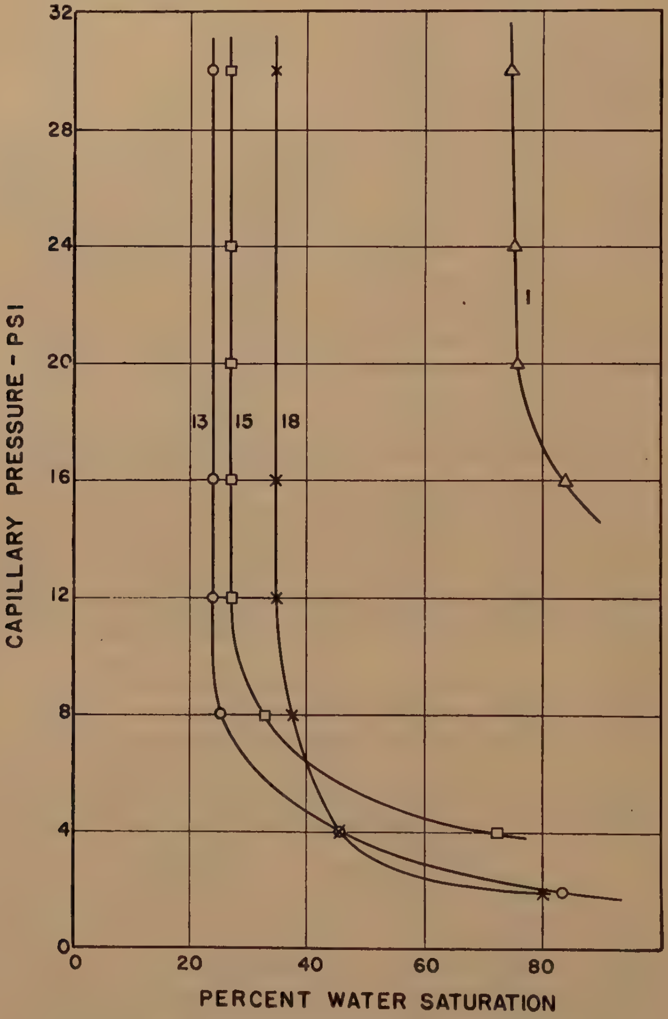

FIG 5—TYPICAL PRESSURE-SATURATION CURVES FOR WELL A.

Table 2 summarizes results obtained by the capillary pressure method applied to core samples from well B (Fig 3), compared with results calculated from the long normal resistivity curves.[1]

The water level in the reservoir from which these core samples were obtained was sufficiently far below the lowest core so that the capillary pressures corresponded with the vertical portion of the curve as described for well A.

Calculations were made from the electric log in the manner described by Archie,[1] using measured values for water resistivity and formation factor. It was assumed there was no effect of invasion of mud filtrate upon the measured resistivity, but correction was made for the presence of the bore hole. The beds were thick enough so that the effect of formation thickness could be neglected.

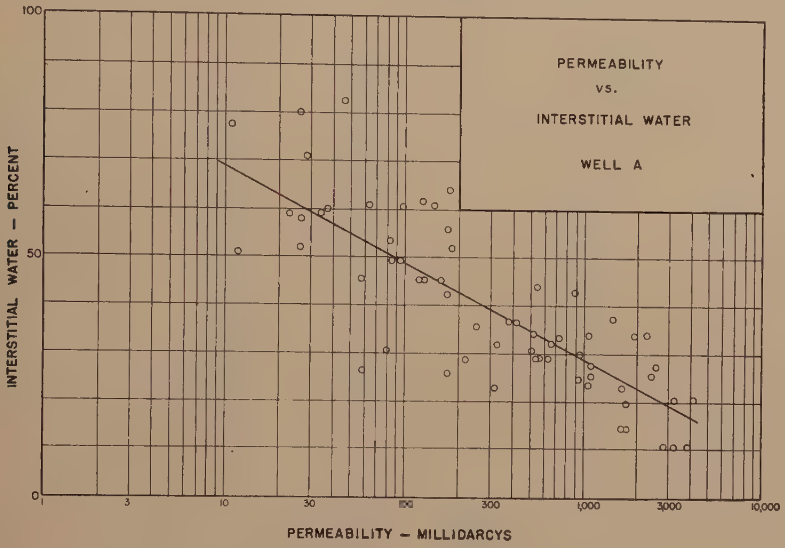

Fig 6.

Discussion of Results

The agreement between the capillary pressure and other methods shown herein, combined with the fact that similar agreement has been obtained by others, indicates that the capillary method properly applied yields results sufficiently accurate for most engineering purposes.

Table 2.—*Water Saturation, Well B*

Depth, Ft	Resistivity Apparent	Meter × Ohms[a] Corrected	Formation Factor	Interstitial Water Saturation, Pct of Porosity	
				Log Method	Capillary Method
10,162–10,172	10	9	10.0	19	19[b]
10,187–10,195	24	18	7.3	11	11[c]
10,195–10,210	32	23	7.3	10	8[d]

[a] The resistivity of reservoir water was 0.031 meter × ohms at 204°F.
[b] Average of five samples.
[c] Average of four samples.
[d] Average of seven samples.

Table 3.—*Use of Electric Log—Well A*

Depth, Ft	Net Sand, Ft	Formation Factor	Interstitial Water Saturation, Pct of Porosity[a]	
			Electric Log	From Table 1
8,665–8,668	3	9.3	26	26
8,692–8,693.5	1.5	9.3	43	44
8,697.5–8,705.5	7.5	9.3	37	37
8,707–8,716	9.0	9.3	37	40
8,721–8,724	3.0	9.3	34	36
8,724.5–8,727.5	3.0	9.3	39	48
8,729.5–8,730.5	1.0	9.3	37	31
8,731–8,736	5.0	6.9	21	23
8,737–8,739	2.0	6.9	30	40
8,740–8,745	5.0	6.9	24	30
8,745–8,752	7.0	6.9	27	31
Weighted average.			31.5	34.6

[a] Values from salinity method, Table 1.

The capillary method is not applicable in many older fields for which sufficient core samples are not available for a representative portion of the reservoir. Also, the method is somewhat time consuming and cumbersome; although it is likely that use of the centrifuge method[7] and other experimental short cuts will be developed and applied in the near future.

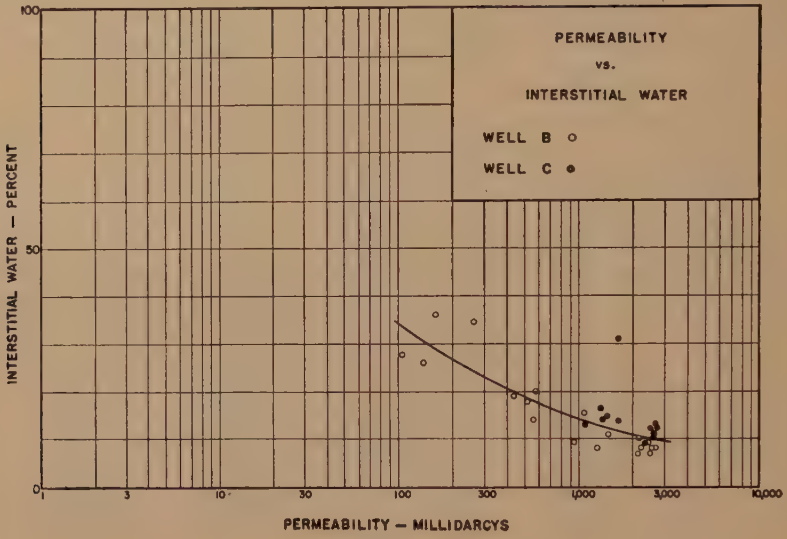

Fig 7.

In some cases, however, interstitial water determined by the capillary method for one or two wells may, by correlation with some other measured physical property, serve as a basis for estimating average water saturation at other points in the same reservoir.

A plot of interstitial water versus specific permeability for samples from well A is shown on Fig 6, and for well B on Fig 7. The data for well A include the determinations made by the salt-content method for samples in addition to those shown in Table 1. Fig 7 includes data from well C, which is in the same reservoir as well B but across the structure approximately 1½ miles.

Both correlations show a general trend, although there is considerable scattering. The average curves shown on the two figures show different values for water saturations of cores with the same permeability, which emphasizes that permeability-water saturation curves should not be used indiscriminately to estimate water saturations in a given reservoir.

In some instances where interpretation of the electric log is difficult, the capillary method may be used to "calibrate" interpretation of the log. Table 3 shows results of such an application to well A, in which the reservoir consisted of interbedded sand, sandy shale, and shale (Fig 2). It was found that fair agreement between interstitial water content calculated from the electric log and that obtained by the capillary method could be obtained if the log was interpreted as follows: use the resistivity recorded with normal electrode arrangement and 16-in. spacing, assume no invasion, no bed-thickness correction, value for formation factor[1] based on *m* of 1.5, resistivity of water equal to 0.030 ohm meters, and observed average porosities.

Electric logs usually are available for all wells and show the entire section, while core samples usually are not available from many wells and core recovery seldom is complete. It is suggested therefore that the capillary pressure and electric log methods may be used together to advantage in determining the distribution of water in some reservoirs.

CONCLUSIONS

From the results herein and those of other investigators, it is concluded that the capillary method may be used to determine the interstitial water content of sands at points above the transition zone. No data are available for limestones or for points within the transition zone for sandstone reservoirs.

The range of utility of the capillary pressure method may be extended by use of correlations between interstitial water content and more easily measured physical properties of the media, such as permeability and electrical resistivity.

ACKNOWLEDGMENT

We wish to acknowledge the services of Messrs. C. B. Scotty and J. B. Glanville, who performed the laboratory measurements of interstitial water. Appreciation is expressed for the suggestions of Dr. W. V. Vietti, under whose supervision the work was done, and to The Texas Company for permission to publish the paper.

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DISCUSSION

E. F. STRATTON*—Mr. Thornton and Mr. Marshall are to be complimented for their significant contribution to our limited, but growing knowledge, of the capillary-pressure technique for determining interstitial water. It has been suggested elsewhere that the interstitial water existing in an actual reservoir might be higher, owing to processes of oil accumulation, than the "irreducible" water obtained from capillary-pressure measurements. The comparison of results obtained by the several methods for determination of interstitial water indicates that the capillary-pressure procedure does duplicate reservoir conditions.

The electric log resistivity curve in many uniform reservoirs with bottom water shows a very sharp change from the oil or gas zone to the water-bearing portions. This would indicate that the "transition" zone is short. On the other hand, vertical changes in the physical properties, for example permeability, of the reservoir may serve to lengthen the transition zone appreciably.

The agreement between determinations of interstitial water by the capillary-pressure method and by electric-log analysis demonstrates that the latter technique can be used in many cases to obtain data quickly and at low cost.

The short-spacing resistivity values and the lack of correction factors for the mud, the borehole, and bed thickness in the electric-log analysis of well A, should not be considered a general application. Conditions existing in this well undoubtedly were favorable for their technique; the procedure used for well B is certainly to be preferred.

G. FANCHER*—The authors are congratulated for an excellent paper on a timely subject of great practical importance, as well as theoretical interest.

We have had some experience with the capillary-pressure method of determining connate water at the University of Texas, employing methods and apparatus like those of Thornton and Marshall, and have found the methods reliable and useful for teaching purposes. We have had little opportunity to check the methods because we do not core wells and have available cores obtained while using oil-base muds. Our cores come from here and there, from friends, and usually we know little about them, but they serve our purpose of instruction and experimentation. Curiously, the first sample run in our laboratory by the capillary-pressure method was a very old piece of Woodbine sand cored during the boom in the East Texas field. We also had Woodbine salt water from the East Texas field available. Enjoying typical beginners' luck, we found from the capillary-pressure curve a connate water saturation of 16.5 pct, a value agreeing nicely with that determined from the electrical log by Archie of 15 pct and the commonly accepted value of 17 pct from analytical determinations.

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The authors apparently had difficulty developing a connate water saturation greater than 90 pct by the technique of immersing samples in water and pulling a vacuum on the submerged samples. We have had little difficulty developing water saturation of 95, 98, and even 99 pct by applying a high vacuum to the dry samples for an hour or so and then introducing sufficient water into the evacuated flask to cover the samples before removal of the vacuum. Of course, this point is academic in that, as Hassler shows, a saturation of 85 to 90 pct is sufficient to yield reproducible results upon desaturation in capillary-pressure tests. Nevertheless, if saturations greater than 85 to 90 pct are wanted, they can be obtained.

We agree with the authors that these tests should be made with salt water from the particular formation, if possible, and, in any event, with water of equal salinity.

Although the explanation attributing the consistently higher connate water saturation by the retort method to bound water is plausible, Dr. Hill in a comprehensive investigation of various methods of determining fluid saturations at Penn State[9] found that so-called "water of crystallization" saturation ranged only from 1.4 to 2.5 pct for samples of the Bradford sand, a notoriously dirty sand, ranging in porosity from 10.6 to 17.6 pct, and in connate water saturation from 12.5 to 38.7 pct.

The authors have demonstrated the value of the capillary-pressure method in determining the connate water saturation above the transition zone. Although the method is tedious, the practical suggestion to employ the capillary tests to calibrate interpolation of parameters more easily and speedily measured is excellent, and we can look forward, I believe, to further development of these ideas. I believe capillary-pressure tests offer so valuable a check that soon they will be routine in core-analysis work. The challenging problem now is the transition zone. First, we need reliable information as to the actual thickness of such zones. If, in general, the transition zone is thin, we need not worry. If, as is likely, it may approach in thickness the oil-bearing zone of irreducible connate water content, to say nothing of the producing zone that is entirely a transition zone, research workers must get busy on accurate determinations and correlations of contact angles; a baffling subject, to say the least.

J. E. Sherborne*—The paper by Thornton and Marshall is a significant contribution to petroleum technology, for it supplements previous papers in substantiating that the capillary-pressure method of determining interstitial water yields results that are representative of conditions actually existing within large portions of our oil-bearing reservoirs. It would appear that sufficient determinations have been made by Messrs. Thornton and Marshall and others over a wide enough range of conditions to justify the wide-spread use of this procedure as a standard laboratory test for the determination of interstitial water.

The fact was noted with interest that the writers obtained erratic results when the water used in the testing by this procedure was of low ionic concentration. It has been the experience in our laboratory that the final equilibrium saturation is affected by the ionic concentration of the brine used. In fact, for most of the samples investigated, there is a distinct shift to a lower equilibrium saturation with an increase in brine saturation. In our experience, however, the shifting has been uniform, so that a family of uniform curves is obtained rather than a series of erratic points. The samples we have examined in this manner, however, all contained relatively large quantities of argillaceous material. The writers' discussion, relative to a comparison between the water saturation of the cores, as obtained by the various methods, is interesting. As is to be expected, the value to be obtained by retorting is somewhat higher than that obtained by the capillary method, but apparently no correction was made for the bound water, which undoubtedly was driven off in the retort process. For precise comparisons, the ASTM method of determining water saturation has been used in our laboratory rather than the retort, since with this method bound water is not liberated and rather close comparisons have been obtained. It has not been possible to obtain reasonable interstitial water values from salinity determinations for the great majority of California cores examined.

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[9] E. S. Hill: Method of Determining the Oil Saturation of Oil Sand Samples. Min. Ind. Expt. Sta. *Bull.* 19 (1935) 59.

* Union Oil Company of California, Santa Fe Springs, California.

It has been our experience that, for the type of cores and fluids encountered under California conditions, cleaning with carbon tetrachloride sometimes apparently does not suffice to remove all of the adsorbed material from the surface of the grains, and it has been found that a further leaching with dioxan has been helpful.

As the authors point out, the procedure is time consuming if enough points are obtained to establish the shape of the capillary-pressure curve; however, it would appear to be their experience, and that of others, that for the large part of the oil-bearing reservoir, under commonly encountered conditions, a value obtained at a sufficiently high pressure so that the saturation will be on the flat part of the curve approaching the "irreducible saturation" would be all that would be necessary. Thus, the choice of some suitable standard pressure, such as for example 30 or 40 lb, would probably in most instances yield a good engineering answer and would materially speed the analysis.

It is hoped that this excellent paper will stimulate more universal use of this method of obtaining much needed information on interstitial water.

Paul Weaver*—In this paper, mention is made that some core samples contained a large amount of clay (p 71). It would seem that much more information could be obtained for comparison with future observations if the cores tested by various methods in the laboratory were photographed so that the type of distribution of sand grains and the distribution of the clay in the core could be seen graphically.

In discussing the reservoirs that are sandstones, mention is frequently made of the sand being "dirty" or "clean," referring apparently to varying amounts of clay in the sand. Not only the amount of such clay is significant as regards both horizontal and vertical permeability, but also its distribution, because in some sands it forms definite layers separated by sand of fairly uniform and large grain size. In other sands, it is distributed in the space between the sand grains. A record of the type of clay distribution, therefore, would aid in interpreting permeability measurements of cores.

J. M. Robinson*—The authors are to be commended for a direct examination of the important problem of determination of the interstitial water saturation of oil sands. The capillary-pressure method for estimating the interstitial water saturation of oil sands is a valuable tool in reservoir studies.

The correlation between permeability and interstitial water saturation must be used with care, as stated by the authors. It has been noted that in such a correlation, increase in the number of data available tends to increase the spread of the points until the relationship becomes merely a trend.

It was reported that saturations of from 80 to 90 pct of the pore space were obtained when saturating the core samples with formation water in capillary-pressure tests. This is in agreement with results in laboratory flooding tests on fresh core samples, in which tests, total saturations vary from 85 to 95 pct of the porosity.

N. van Wingen†—Messrs. Thornton and Marshall's paper is of particular interest in that it presents additional field data comparing the results of various methods for estimating interstitial water saturations. It is to be hoped that others will feel similarly prompted, as only the availability of numerous data of this nature for many reservoirs of several types will establish definitely whether or not the minimum saturation values, as obtained by the capillary method, can be considered to be representative of true reservoir interstitial water values. In other words, the point to be established is whether oil reservoirs in general are in such a state of capillary equilibrium that their interstitial water content is truly "the irreducible minimum."

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Another important consideration in this regard is the formation of an adequate concept regarding the thickness of transition zones. Thin transition zones are suggested on the basis of the work of Katz, Monroe and Trainer[10] as they conclude that the magnitude of water-oil interfacial tension in most reservoirs may have been generally overestimated. In support of this contention, it is of interest to note the results of Thornton and Marshall's well A, where comparable saturations for various methods were obtained to within 22 ft of the oil-water interface. It would be of interest if the authors could similarly identify the position of the water level in their well B.

O. F. Thornton (author's reply)—The water level in the sand of well B is at a depth corresponding to 10,230 ft, or 20 ft below the lowest core sample analyzed.

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[10] Surface Tension of Crude Oils Containing Dissolved Gases. *Petr. Tech.* AIME (Sept. 1943—TP 1624).

The Performance of Bottom Water-drive Reservoirs

BY MORRIS MUSKAT,* MEMBER A.I.M.E.

(Chicago Meeting, February 1946)

ABSTRACT

A THEORY has been developed describing the behavior of wells and reservoirs producing by the action of bottom water drives. It is assumed that the pressures are maintained above the bubble point, and that the permeability to viscosity ratio of the water in the flooded zone is the same as for the oil in the oil-saturated pay. Accordingly, the treatment is based on the homogeneous fluid potential theory. The effect of the difference in density between the oil and water is neglected. After deriving the proper potential distributions, the nature of the rise of the water-oil interface below the producing wells is calculated. The primary clean-oil-production phase is expressed in terms of the displacement efficiency, defined as the fraction of the pay flooded out by the rising water table at the time of first water entry. The variation of this displacement efficiency is calculated as a function of the well spacing, pay thickness, the ratio of the horizontal to vertical permeability, and the well penetration. The important parameter, other than the well penetration, is found to be the ratio of the well separation to the thickness of the oil pay multiplied by the square root of the ratio of vertical to horizontal permeability. It was found that the displacement efficiency continually decreases as this parameter increases, and for values of the latter >3.5, the efficiency varies inversely as the square of the parameter. It also increases with decreasing well penetration. Perhaps the most striking result of this phase of the analysis is the conclusion that in order to explain the delay in entry of water in wells producing by bottom water drives for periods longer than a few days normal production, with drawdowns large compared with the differential density head between the oil and water, it is necessary to assume that the vertical permeability is a very low fraction of the horizontal permeability.

An analysis is also given of the production history after the water has broken through, on the assumption that the production mechanism and details of the flow distribution continue to be the same as during the phase of clean-oil production. As is to be expected, it is found that the water cut will increase at an accelerated rate as production proceeds. However, the initial differences between systems of different well penetrations or well spacings with respect to the total clean-oil production gradually decrease in terms of the variation of the water-oil ratio with cumulative production. In particular, by the time the water-oil ratio has reached values of the order of 5 or greater the cumulative recoveries will generally differ much less among various producing systems than their corresponding clean-oil recoveries.

INTRODUCTION

On the basis of elementary geological principles, one may classify effective water-drive fields in two groups. In the first, the entry of water into the oil-producing formation may be characterized as an edge-water encroachment. This term is used to suggest that the motion of the water proceeds largely in a direction parallel to the planes of stratification. This type of water intrusion occurs usually in thin producing zones and in strata lying along structural flanks of appreciable dip. In the second group—"bottom water-drive" fields—the water-oil interface lies in a plane of zero or slight inclination to the

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* Gulf Research and Development Co., Pittsburgh, Pennsylvania.

bedding planes of the producing formation. The latter class will be more prevalent in thick producing formations or where the oil-bearing zones have low relief. Of course, no sharp difference between the two groups is to be anticipated in practice, and the physical behavior of actual oil reservoirs will be a resultant effect of the unique characteristics of each idealized extreme type. In fact, even when the field as a whole is controlled by an edge-water drive mechanism, the edge wells will generally show a bottom water-drive type of history. However, for the purposes of quantitative discussion, it is convenient to concentrate upon these idealized limiting cases, and consider intermediate situations as representing an appropriate superposition of the two defining prototypes.

It is difficult to treat quantitatively the detailed dynamics of the edge-water encroachment type of water-drive field, because the productive histories of such fields are progressive, as the water moves in from the original boundaries and continually shrinks the productive area. The direct interplay between the advancing water and the oil-producing wells is not uniformly applied to all the wells in the field, but continually shifts from the edge-water boundaries to the more distant regions, as production proceeds. What will happen may then depend materially upon what is done to the wells directly affected by the edge water and perhaps encircled by it. Physically, the situation corresponds to what may be termed a multiple well system produced by virtue of an advancing line drive flood, and a first approximation theory can be constructed using such a representation.

In the case of the bottom water-drive fields, the situation is appreciably different. Here, at least in the limiting idealized case where the bottom water is spread uniformly under the whole productive area of the field, all the wells, if operated similarly, will experience similar or identical histories. From a qualitative point of view, it is not difficult to predict the history of the production and the course of the water intrusion for such systems. Under the relatively high reservoir pressure obtaining within the water zone, and at the base of the oil zone, and the reduced bottom-hole well pressures, the water will be subjected to an appreciable pressure differential distributed over the oil-saturated zone. The flow lines will be normal to the original water-oil interface, and will be generally directed upward until the part of the producing stratum penetrated by the well is approached, when they will be deflected so as to proceed toward the well bores. A diagrammatic representation of this situation, though not to scale, is shown in Fig. 1.

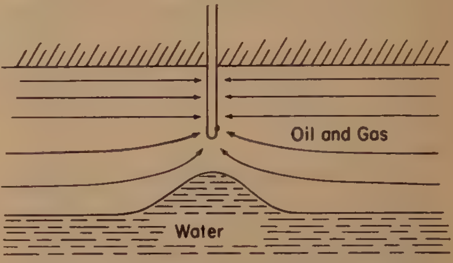

Fig. 1.—Diagrammatic representation of flow system under complete bottom water-drive conditions.

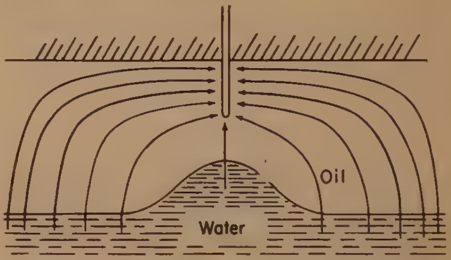

Fig. 2.—Diagrammatic representation of flow conditions in a gas-drive system underlain by a mobile water table.

It is important to understand clearly the contrast between the flow system represented in Fig. 1 and that generally referred to as "water coning."[1,2] Strictly speaking, the latter applies only to a

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[1] References are at the end of the paper.

situation wherein the oil expulsion is not induced by the contiguous water but rather by another agency, such as its own internal dissolved gas. Even without the presence of the water, the oil would undergo an essentially horizontal flow toward the well, as indicated in Fig. 2, in contrast to the predominantly vertical flow in the problem to be considered here. Thus, in the case of the "water-coning" problem the bottom water represents merely a mobile interface with the oil zone, but does not provide the drive for the oil. The oil moves toward the wells because it is displaced or swept along by the gas evolved in the sand. Under stable conditions, therefore, the bottom water may lie statistically beneath the oil zone, and exert no material influence on the production of the oil. Here, however, it is the water that is the driving agent, and the flow of the oil into the well is assumed to take place only by virtue of its displacement by the rising water table.*

Although the maximum rate of vertical advance of the oil-water interface in a bottom water-drive system will clearly be along the well axis, the vertical velocity will not become negligible until the interface has receded an appreciable distance from the axis of the well. There will thus form a conelike rising interface with its apex along the well axis. However, the sharpness of the apex of the conelike interface will be accentuated as the water rises, and ultimately will take the form of a cusp as it reaches the bottom of the well. As long as the lateral spread of the elevated water table is less than half the distance between neighboring wells, each well will be flooded out independently and the oil recovery will be simply proportional to the number of wells in the system. But as the number of wells increases, and the spacing decreases, so that there is overlapping in the regions of appreciable water elevation, the region midway between the wells will be shared by the mutual neighbors with respect to the flushing action of the water. Still closer spacing will then result in less than a proportionate increase in the recovery, and the latter will ultimately approach a constant value corresponding simply to the total oil available to be displaced by the water. Thus, in the region of wide spacing the recovery before water entry will be approximately proportional to the well density, whereas it will gradually become independent of the well density as the well spacing is continuously decreased.

While the quantitative fixing of the well separation that will physically represent wide or close well spacing must be determined by calculation, one may anticipate the predominant factors from general considerations. The first is clearly the thickness of the producing section. Obviously, this thickness must represent the basic unit by which to measure the lateral spacing; that is, in a thin sand, moderate well separations would appear to represent a wide spacing, whereas if the sand were thick the same well separation would be equivalent to a close well spacing.

Another important factor is the isotropy of the sand with respect to its permeability for horizontal as compared to vertical flow. Here again it is clear that if the vertical permeability is comparable to or greater than the horizontal permeability, the bottom water will tend to form a narrow cone as it rises toward the well, and even a moderate well separation will become equivalent to a wide spacing. On the other hand, if the vertical permeability is considerably lower than the horizontal permeability, the conelike water-oil interface will be rather flat, and will give an oil-displacement history similar to the one that otherwise would obtain under close well spacing.

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* It must be recognized, of course, that in actual producing systems the bottom water will tend to encroach into the oil pay even if the production begins under an essentially gas drive mechanism.

The degree of well penetration also evidently will affect the detailed histories of the individual wells. If the well is bottomed very near the water-oil contact the water will enter the well early in its productive life; and as the calculations will confirm, one may expect the clean-oil production to be a maximum, if the well just taps the top of the oil pay.

Assumptions

Before presenting the results of the analytical developments, which are fully outlined in the Appendix, the basic assumptions underlying the treatment should be noted. These are:

1. The pressures throughout the system are above the bubble point.
2. The system is operating under steady-state conditions.
3. The permeability to viscosity ratio for the oil above the water-oil interface is the same as for the water in the flooded part of the oil pay.
4. There is no oil stripping in the flooded region.
5. The density difference between the oil and water may be neglected.

Assumption 1 simply limits the considerations to the complete water-drive type of systems, where no aid in oil expulsion is derived from gas evolution. The second assumption enters the analysis in the requirement that the pressure at the original water-oil contact—assumed horizontal—remains constant. This, of course, will not be true when the source of the water is the fluid expansion in the water reservoir. On the other hand, as long as assumptions 3, 4 and 5 are also made, assumption 2 really adds no basic additional limitation on the validity of the results.

Assumption 3 is made solely because of analytical necessity. Otherwise a detailed treatment as given here would be virtually impossible. That this assumption would be strictly valid in practice would be purely accidental. Published data on unconsolidated sands[3] suggest that this ratio may be less for oil than for the water. On the other hand, there is some evidence from experiments with consolidated sand that the permeability to the water phase in the water-flooded region may be considerably lower than indicated by Leverett, so as to make the permeability to viscosity ratio lower than for the oil in the unflooded pay. If this is true, the sharpness of the conelike interface would be less than as derived on the basis of assumption 3; and, conversely, if Leverett's data are applied to consolidated sands. Because of the uncertainty as to the actual situation, the assumption of equality would appear to be justified, even aside from analytical demands. Moreover, it may be noted that this assumption also underlies the use of electrolytic models for studying water-flooding patterns.

The fourth assumption is also made primarily for the sake of analytical simplicity. Taking the stripping into account should not materially affect the calculated "displacement efficiencies" (to be discussed later) though it will lead to a somewhat slower rise in the water-oil ratio after the water has broken through. For practical purposes, however, the contribution to the total oil production from the flooded region, in homogeneous sands, is felt to be of minor importance.

The last assumption implies that all the basic phenomena characterizing the bottom water-drive systems are independent of the *rates* of production. That is, the displacement efficiencies and development of water cuts vs. cumulative recovery will be dependent only on the geometrical and physical constants of the system, but will not be changed by variations in the production rate. The latter will affect only the time scale.

This basic assumption cannot be rigorously maintained. Undoubtedly the gravity difference between the oil and water will tend to retard and flatten the conelike development of the water-oil interface. This effect will be greatest at low rates of production and where the producing pressure differential is a minimum. In the extreme case, where the well may be shut in for extended periods, the water elevation immediately about or below the well will decline, and an equalization of the interface level will tend to be established. In principle, therefore, both the displacement efficiencies and development of water-oil ratio, as calculated here, will represent the least favorable conditions,* and will be subject to some improvement by taking advantage of the gravity effects and restricting the production rate or by producing intermittently. From a practical point of view, however, it is expected that the value of such control will be quite limited, unless the producing pressure differentials are made comparable to the equivalent fluid head of a density equal to the difference between the oil and water, or a truly intermittent operating cycle, with extended shutdown intervals, can be used. Under such conditions significant differences in performance from that predicted here may well arise. While the importance of taking into account the gravity effects is fully recognized, to do so would involve an even higher degree of complexity than the rather laborious analysis required for the present study. Accordingly, as long as the indicated limitations of the theory are kept in mind, there should be no difficulty in properly applying the results presented in the following pages.

DISPLACEMENT EFFICIENCY FOR WATER-FREE PRODUCTION

In representing the relative behavior of various producing systems with different physical parameters, such as well spacing, pay thickness, permeability and well penetration, it is convenient to introduce the term "displacement efficiency." This term is completely analogous to the flooding efficiency that is used in describing areal water-flooding systems, and is given by the ratio of the volume of the sand flushed out by the time water reaches a producing well to the total volume of sand associated with the well. The numerical value of this efficiency will, of course, vary between 0 and 1. Low values indicate that the water quickly enters the producing well while flushing out only a small part of the pay, and the limiting value 1 implies that all of the producing section has been uniformly flushed out by the time the water enters the producing wells. If we assume that the latter are distributed in a regular pattern of effective spacing a, and h is the oil-saturated zone thickness, then the displacement efficiency will be defined by:

$$\text{Displacement efficiency} = E = \frac{V}{ha^2} \quad [1]$$

where V is the volume of pay per well that is flushed out by the time the water first enters the producing well.

It is to be noted that V is proportional only to the clean-oil production from the well, so that E is likewise a measure only of the water-free production. It is recognized, of course, that the clean-oil production period represents only one phase of the whole production history. However, the development of the water cut in the production will be treated later. As in the areal flooding problem, it is most convenient for analytical purposes, and also of physical interest, to treat these two phases separately.

The details of the analysis will be given in the Appendix. Here it will suffice to present the final results. These are composed of the set of curves plotted in Fig. 3.

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* If the permeability to viscosity ratio should be greater for the water in the flooded region than for the oil in the oil-saturated pay, there will be at least a partial compensation effect between assumptions 3 and 5.

It will be noted from Fig. 3 that the displacement efficiency has been plotted against a parameter $\bar{a}$, and separate curves are shown for different values of ρ_w. These are defined by the equations:

$$\bar{a} = \frac{a}{h}\sqrt{k_z/k_h};\ \rho_w = \frac{r_w}{2h}\sqrt{k_z/k_h} \qquad [2]$$

where a is the effective well separation, h the initial thickness of the oil-saturated pay, r_w is the well radius, and k_z, k_h are the vertical and horizontal permeabilities, respectively. Accordingly, $\bar{a}$ and ρ_w may be considered as dimensionless well-spacing and well-radius parameters.

The reasons why the well spacing a itself cannot uniquely determine the behavior of the system were discussed in the Introduction. It will be instructive, however, to show more explicitly why it is basically necessary to treat the bottom water-drive systems as anisotropic, instead of taking advantage of the apparent simplification of isotropy, for which $k_z/k_h = 1$ Thus, for example, suppose it were assumed that k_z/k_h were 1. Then if the well spacing were 330 ft. (2½ acres per well), and the pay thickness 25 ft., $\bar{a}$ would equal 13.2. For a 6-in. well bore, ρ_w would equal 0.005. If the well penetration were 50 per cent,

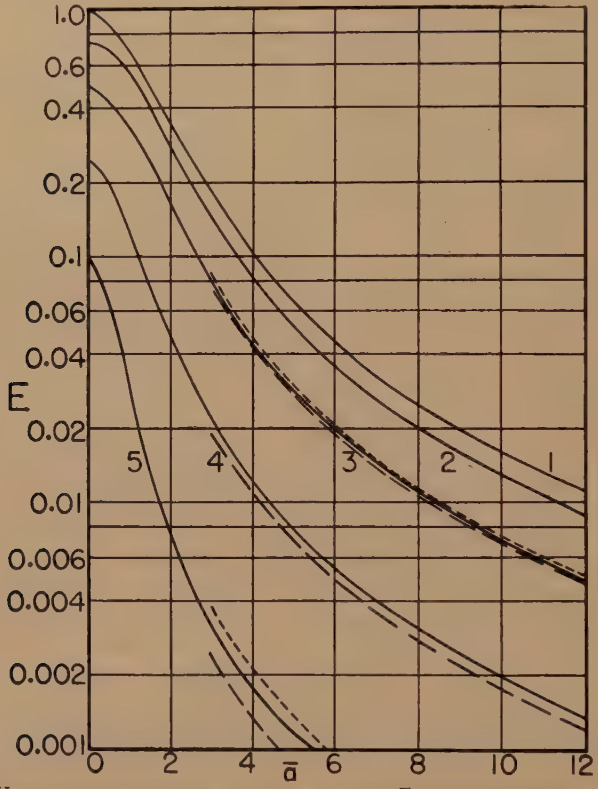

FIG. 3.—VARIATION OF DISPLACEMENT EFFICIENCY E WITH SPACING PARAMETER $\bar{a}$.

E = (sand volume flooded out by time of water entry)/(total sand volume drained by well). Well penetration = "zero," 25 per cent, 50 per cent, 75 per cent and 90 per cent for curves 1, 2, 3, 4 and 5, respectively.

For solid curves, $\rho_w = 0.001$; for upper dashed curves, $\rho_w = 0.0002$; for lower dashed curves, $\rho_w = 0.005$. $\bar{a}$ and ρ_w are defined by Eqs. 2 of text.

a slight extrapolation of the corresponding curve of Fig. 3 shows that the value of E would be 0.0039. From the definition of E, this means that less than 0.4 per cent of the volume of pay drained by the well would be flushed out by the time water would appear. For a porosity of 25 per cent and a local oil displacement of 60 per cent of the pore space, the volume of clean production would be only 283 bbl. of reservoir oil. At a production rate of 100 bbl. per day, water would thus appear within three days.

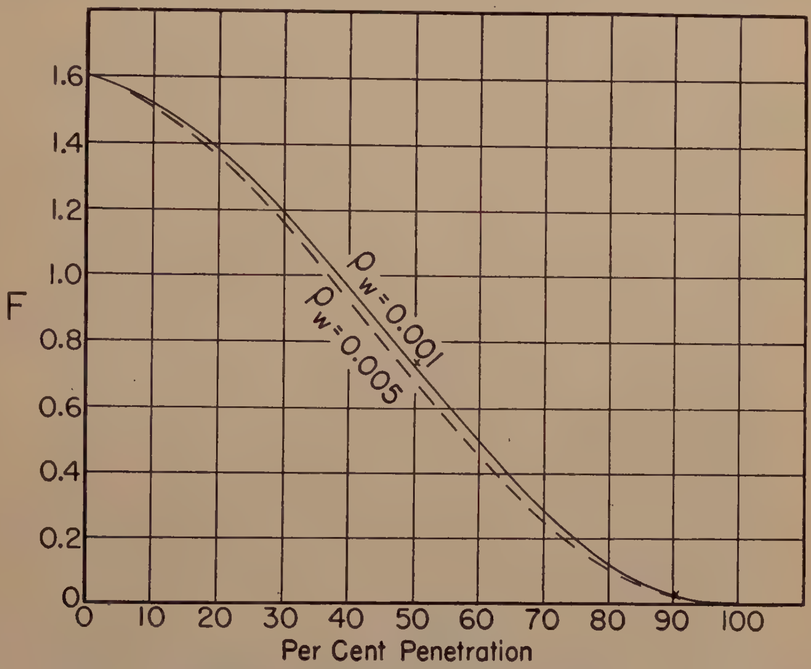

Fig. 4.—Variation of efficiency function F defined by Eq. 3 of text and Eq. 28 in Appendix, with the well penetration.
x indicates values for $\rho_w = 0.0002$, as defined by Eq. 2.

Further examples of this kind can be readily worked out on noting, as will be proved in the Appendix, that for large values of $\bar{a}$, and in particular for $\bar{a} > 3.5$, the displacement efficiency E takes the simple form:

$$E = \frac{F}{\bar{a}^2} \qquad [3]$$

where F is a constant, depending on the well penetration and ρ_w, as shown graphically in Fig. 4. Recalling Eqs. 1 and 2, it follows that the volume of oil pay flushed out by the time of first water entry is (for $\bar{a} > 3.5$):

$$V = \frac{Fh^3k_h}{k_z} \qquad [4]$$

Hence the volume of clean-oil production per well, in barrels (h in feet), is:

$$\bar{Q} = \frac{Ff\,dh^3k_h}{5.61\alpha k_z} \qquad [5]$$

where f is the porosity and d the microscopic displacement efficiency of the oil flushing expressed as a fraction of the pore space,* and α is the formation volume factor.

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* d may be defined more explicitly as $1\text{-}\rho_w\text{-}\rho_{or}$, where ρ_w is the connate water and ρ_{or} the residual oil saturation.

If the basic treatment of this problem is fundamentally sound, it is obvious that the assumption of isotropy would be quite untenable. On the contrary, as will be discussed later, to explain such periods of clean-oil production, and their corresponding displacement efficiencies, as are observed in practice, with pressure differentials large compared with the differential gravity head between oil and water, it is necessary to assume that the producing formations are in effect decidedly anisotropic, the vertical permeabilities being but small fractions of one per cent of the horizontal permeability.

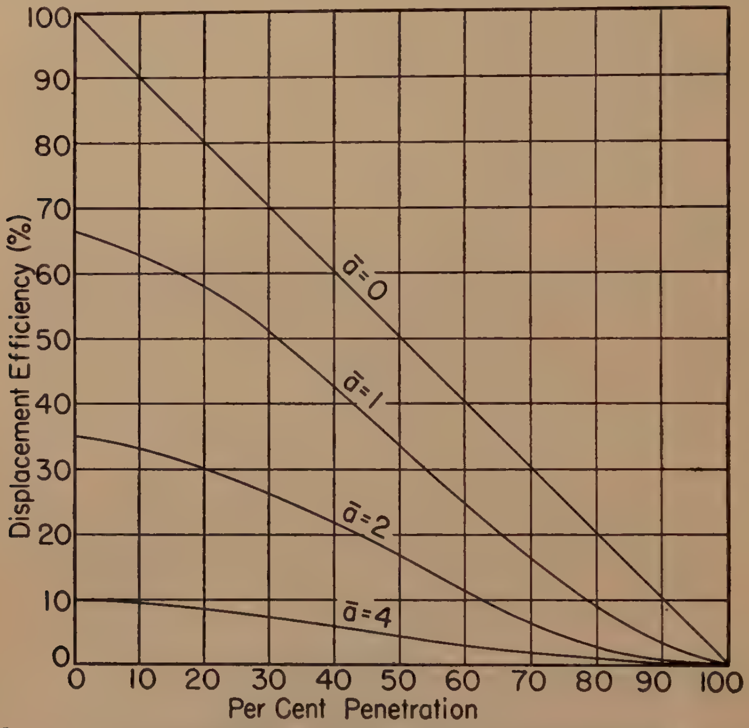

FIG. 5.—VARIATION OF DISPLACEMENT EFFICIENCY WITH WELL PENETRATION FOR $\rho_w = 0.001$, AND VARIOUS VALUES OF WELL-SPACING PARAMETER $\bar{a}$.

Returning now to Fig. 3, it will be seen that the displacement efficiency for fixed well penetration and ρ_w uniformly decreases with increasing well spacing parameter $\bar{a}$. And as indicated by Eq. 3, for $\bar{a} > 3.5$, E varies inversely as the square of $\bar{a}$. In this range E varies linearly with the well density, and with the square of the oil-pay thickness. On the other hand, as shown by Eq. 5, the total clean-oil production per well, for $\bar{a} > 3.5$, will be independent of the well spacing, but will increase with the cube of the oil-pay thickness and the ratio of the horizontal to vertical permeability. This evidently means that there will be no appreciable interactions between the water rise of the various wells, and each will have a history as if it alone were draining the pay.

For close effective well spacings, $\bar{a} < 3.5$, Eq. 3 breaks down, as, of course, it should, because E cannot physically exceed unity. Indeed, it may be anticipated, and is confirmed by Fig. 3, that in the limit of zero spacing E should reach a maximum value equal to the fraction of the oil pay below the bottom of the well. For in the region of close spacings the wells will interfere with each other and their local water-oil interfaces will overlap, tending to flatten out the sharp conelike form. And in the limit of zero spacing, the interface will be uniformly flat and completely flush out the pay below the bottoms of the wells before entry of water.

As also shown by Fig. 3, the displacement efficiency decreases with increasing well penetration. Direct plots of E vs. well penetration for fixed values of $\bar{a}$ are given in Fig. 5. The curve for $\bar{a} = 0$ is exactly linear, and the others show inflections and a flattening of the curves at the higher well penetrations.

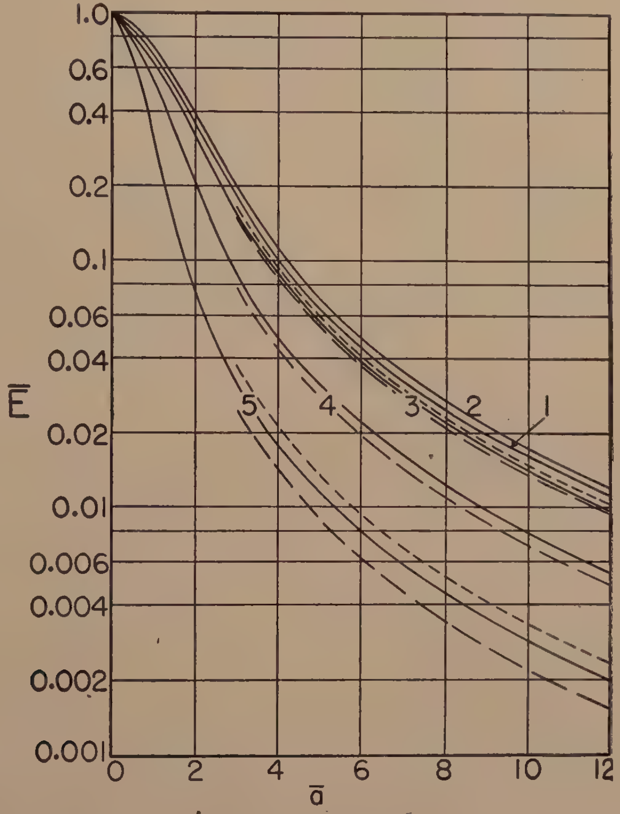

Fig. 6.—Variation of effective displacement efficiency $\bar{E}$ with well-spacing parameter $\bar{a}$.

Curves 1, 2, 3, 4 and 5 refer to well penetrations of "zero," 25 per cent, 50 per cent, 75 per cent, and 90 per cent, respectively.

Solid curves are for $\rho_w = 0.001$. Upper dashed curves are for $\rho_w = 0.0002$, and for lower dashed curves $\rho_w = 0.005$.

The dashed curves in Fig. 3 show the effect of ρ_w on the displacement efficiency, and, in particular, if the other parameters are considered fixed, that E increases with decreasing well radius. The reason is that as the well radius becomes smaller the degree of concentration about the well of the total pressure drop increases, so that the residual distribution near the water-oil contact becomes more nearly uniform and induces a somewhat flatter rise of the interface. As is to be expected, this whole effect becomes less important as the well penetration decreases. For 25 per cent penetration the curves for $\rho_w = 0.0002$ and 0.005 virtually coincide with that shown for $\rho_w = 0.001$, and for the "nonpenetrating"* well, the effect of ρ_w disappears entirely.

The great divergence between the curves in Fig. 3 for different well penetrations, of course, arises because the whole oil-pay thickness is included in expressing the displacement efficiency; i.e. by Eq. 1. This means that even in the limit of zero well spacing, E will decrease linearly with the penetration (cf. Fig. 5). For a more appropriate comparison of the results for different well penetrations it would appear to be better to express the displacement efficiency in terms of the part of the oil-saturated section below the bottom of the well; that is, we may define an *effective* displacement efficiency $\bar{E}$ as the fraction of the pay below the well flooded out by the time of first entry of water. In terms of E, this quantity will be:

$$\bar{E} = \frac{E}{1 - 2\bar{\ }} \qquad [6]$$

where $\bar{x}$ is half the penetration, expressed as a fraction of the oil-pay thickness.

$\bar{E}$ is plotted as a function of $\bar{a}$, for different well penetrations, in Fig. 6. Again, the dashed curves refer to $\rho_w = 0.005$, or 0.0002, whereas for the solid curves $\rho_w = 0.001$.

As implied by the definition of $\bar{E}$, it assumes the value 1; i.e., 100 per cent effective displacement efficiency, in the limit of zero well spacing, regardless of well penetration. For nonvanishing well spacings, however, the curves still diverge. For the greater well penetrations even the effective displacement efficiencies are lower than those for the nonpenetrating well, although the differences are not as great as in Fig. 3. On the other hand, for penetrations less than 40 per cent, $\bar{E}$ becomes even greater than for the nonpenetrating well. These effects represent the resultant between two opposing factors tending to change the character of the rise of the water-oil interface as the well penetration is varied. One is that in the wells of greater penetration virtually all the streamlines terminate along the well surface above the bottom (cf. Fig. 15), and hence tend to equalize the rise in the water table even at appreciable distances from the well axis. On the other hand, the decreasing pay section below the bottom of a well as the penetration increases is equivalent to an increasing effective well spacing. In terms of displacement efficiency the latter effect always predominates. However, when the resultant behavior is expressed as an *effective* displacement efficiency, the balance is much closer, and at the smaller penetrations the first factor becomes controlling.

As an illustration of the numercial significance of these curves, we may suppose that the true well spacing is 660 ft. (10 acres per well), that $k_h/k_z = 25$, and that the total thickness of the oil-saturated section is 25 ft. By Eq. 2 the dimensionless well spacing $\bar{a} = 5.28$. Hence, for a nonpenetrating well ($F = 1.60$), Eq. 3 gives for the efficiency: $E = 0.0574$; *i.e.*, a flooding of 5.74 per cent of the pay by the time of entry of water. If the well has a nonvanishing penetration, we first note that for these conditions $\rho_w = 0.001$ (for a well radius of ¼ ft.). Then, by reference to Fig. 3 or 4, it is seen that if the well penetration is 90 per cent, $E = 0.0010$; if it is 75 per cent, $E = 0.0070$; if it is 50 per cent, $E = 0.025$, and if the well penetration is 25 per cent, $E = 0.046$; that is, the clean-oil production will be equivalent, respectively, to 0.10, 0.70, 2.5 and 4.6 per cent flooding of the total sand volume drained by the well, as compared with 5.74 per cent for the nonpenetrating well. On the other hand, in terms of the section below the bottom of the well, Fig. 6 shows that for these penetrations, 1.0, 2.8, 5.1 and 6.1 per cent, respect-tively, of the pay will be flooded out by the time of first water entry.

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* The term "nonpenetrating" or "zero" penetration is used in this paper to indicate that the well just taps the producing section with a penetration only of the order of the well radius.

The role played by the well penetration can be further illustrated by a computation of the degree of anisotropy required to give fixed effective displacement efficiencies for different well penetrations. Thus, taking again the case where $a = 660$ ft. and $h = 25$ ft., we may compute the ratio k_h/k_z required to give any preassigned efficiency for different well penetrations. In particular, if the effective displacement efficiency be taken as 25 per cent ($\bar{E} = 0.25$), and the well penetration as 90 per cent ($\bar{x} = 0.45$), the corresponding curve for $\rho_w = 0.001$ in Fig. 6 shows that $\bar{a}$ must have the value 1.11. It follows then from Eq. 2 that:

$$\frac{k_h}{k_z} = \left(\frac{660}{25\bar{a}}\right)^2 = 565$$

Carrying through similar calculations for the other well penetrations, the results listed in Table 1 are obtained.

TABLE 1.—*Permeability Ratios Required to Give 25 Per Cent Effective Displacement Efficiency in a 25-foot Sand, and Well Spacing of 660 Feet*

Well Penetration, Per Cent	$\bar{a}$	k_h/k_z	h', Ft.	$10^4\rho_w$
"Nonpenetrating"	2.50	112	264	
25	2.62	102	252	5.0
50	2.35	126	281	4.5
75	1.85	204	357	3.5
90	1.11	565	595	2.1

The values of h' in the table are the equivalent values of the pay thickness for an isotropic sand. The ρ_w are those calculated, according to the definition of Eq. 2, and corresponding to the listed values of k_h/k_z. As the latter were determined by reference to the curves of Fig. 6 for $\rho_w = 0.001$, a correction should be made to obtain a strictly accurate value of k_h/k_z. However, the spread among the curves in Fig. 6 for the different values of ρ_w is so limited that the effect may be neglected for illustrative purposes.

As would be anticipated from the position of the 25 per cent curve in Fig. 6, the permeability contrast required for the 25 per cent penetration is somewhat less than for the nonpenetrating well. However, for the higher penetrations, the contrast is considerably greater. On the other hand, if these partially penetrating well systems had been approximated by nonpenetrating wells placed at the bottoms of the actual wells, the required permeability anisotropy for 25 per cent effective displacement efficiency would have been much greater. Thus for 75 per cent penetration, k_h/k_z would have had to be 1784 for the nonpenetrating equivalent, as compared with the indicated value of 204; and for 90 per cent penetration, a 25 per cent efficiency could not be achieved with the simulated nonpenetrating well unless k_h/k_z were 11,150 as compared with 565 given in Table 1.

The high degrees of anisotropy required for explaining even moderate displacement efficiencies, according to these calculations, may appear quite surprising. These have not been indicated by core analyses, which generally show at the most only an order of magnitude difference between the vertical and horizontal permeabilities, and sometimes even indicate higher permeabilities perpendicular to the bedding planes than parallel to them. This apparent discrepancy, however, can be at least rationalized. In the first place, vertical permeability measurements are not often made in routine analyses. Secondly, if the low effective permeability were visualized as resulting from a dissemination through the rock of very thin and perhaps microscopic shale or micaceous laminations, it might be expected that the cores would part at these interfaces and the layers adhering at the end faces would be removed on preparing the sample for measurement. In any case, the vertical permeability of significance here is a resultant value of whatever geometrical distribution of individual and localized strictly impermeable elements embedded in the main, and perhaps isotropic, sand matrix; and it may also be observed that while the attempt is generally made to place packers opposite shale or impermeable streaks, it is doubtful whether this is actually achieved in all the successful installations. It might well be that the type of anisotropy considered here is also often responsible for the effective sealing action of formation packers.

In Fig. 7 the displacement efficiencies for $\rho_w = 0.001$ are plotted vs. $1/\bar{a}^2$. In a reservoir of fixed physical properties, $1/\bar{a}^2$ is proportional to the well density; i.e., wells per acre, or the total number of wells in a given area. Moreover, *E* may be interpreted as the ratio of the volume of the whole oil pay flooded out by the time of first water entry to the total volume of the pay. Fig. 7 thus shows the variation of the total clean-oil production from a given area with the number of wells. The horizontal dashed segments above the individual curves locate the corresponding asymptotes for infinite well density. To interpret the abscissas in Fig. 7 in practical units, it is to be noted that the choice of ρ_w fixes the product of the oil-pay thickness and the square root of the permeability ratio. Accordingly, with $\rho_w = 0.001$, $1/a^2 = 1$ corresponds to 2.788 wells per acre. The major part of the range in $1/\bar{a}^2$ shown in Fig. 7 thus represents developments with very close well spacings. In the region of wider spacings, near the origin, the clean-oil production appears to increase linearly with the well density. This, however, is because of the value 0.001 taken for ρ_w which corres-

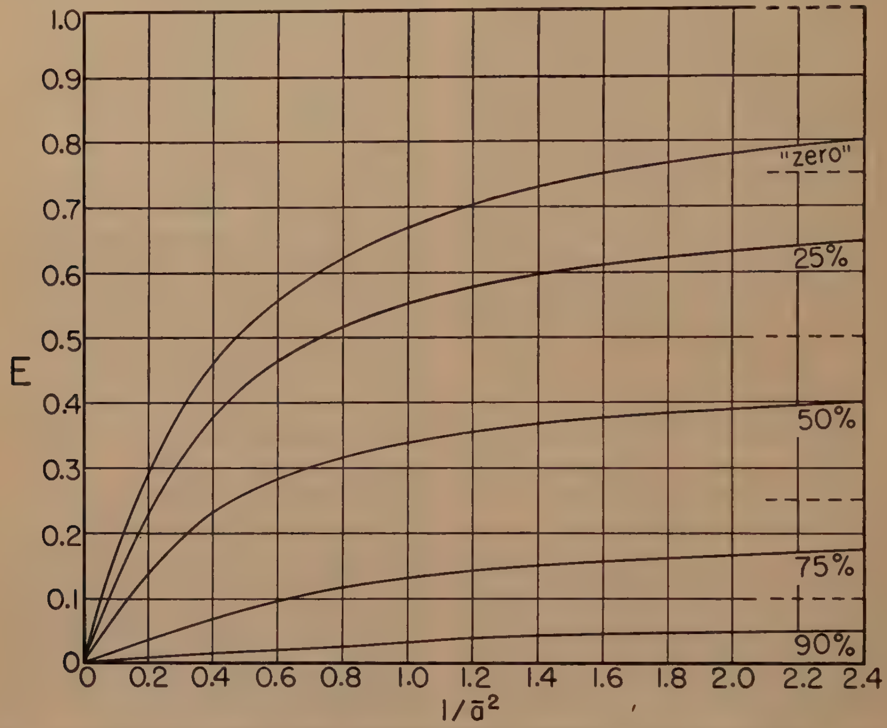

FIG. 7.—VARIATION OF DISPLACEMENT EFFICIENCY WITH RECIPROCAL OF SQUARE OF WELL-SPACING PARAMETER, FOR FIXED WELL PENETRATIONS, GIVEN BY NOTATION ON CURVES.

Dashed segments above curves indicate asymptotic limits of displacement efficiency at infinite well densities.

ponds to only a moderate degree of permeability contrast, for practical values of pay thickness. If ρ_w we taken as 0.0001, the curves in Fig. 7 would not only be raised somewhat (cf. Fig. 3), but $1/\bar{a}^2 = 1$ would now correspond to a well density of 0.028 wells per acre; i.e., 36 acres per well. These considerations show again that to explain the general features of observed field performance it is necessary to postulate or infer an extreme degree of anisotropy in the effective permeability of the producing section.

In the Appendix will be developed the formulas for computing the production capacities of wells producing under the action of bottom water drives. The results, plotted as a function of the well penetration, for various values of ρ_w and well spacing, are shown in Fig. 8.* For comparison

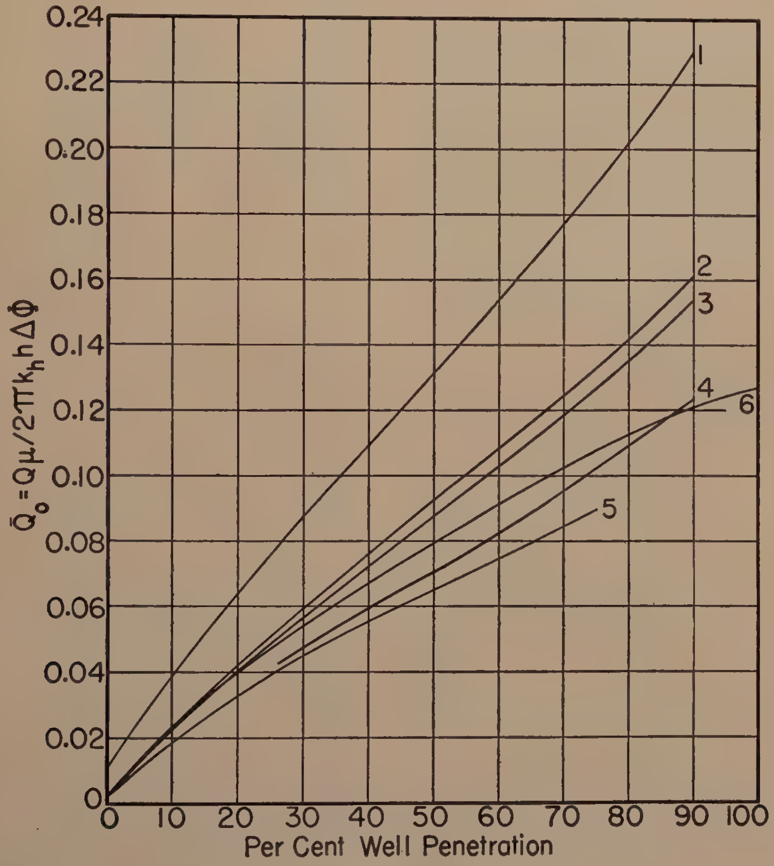

FIG. 8.—VARIATION OF DIMENSIONLESS PRODUCTION CAPACITIES $\bar{Q}_0$ OF PARTIALLY PENETRATING WELLS PRODUCING BY BOTTOM-WATER DRIVES, WITH WELL PENETRATION.

For curve 1, $\rho_w = 0.005$, $A = \infty$; curve 2: $\rho_w = 0.001$, $A = \infty$; curve 3: $\rho_w = 0.001$, $A = 1$; curve 4: $\rho_w = 0.0002$, $A = \infty$; curve 5: $\rho_w = 0.001$, $A = \frac{1}{8}$.

Curve 6 refers to partially penetrating wells in steady-state radial drive systems.

Q = production rate; μ = oil viscosity; k_h = horizontal permeability; h = thickness of oil section; $\Delta\phi$ = potential drop; A = spacing in acres per well.

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* The capacities plotted in Fig. 8 are not corrected for shrinkage to stock tank conditions, but refer only to reservoir volumes units.

ison a curve is included for the steady-state edge-water type of drive in a 125-ft. sand with a ratio of external to well radius of 2640, which corresponds to a 31.4-acre spacing if the well radius is ¼ ft. The ordinates are plotted in dimensionless form. The production capacities are of comparable magnitude, and increase with well penetration in a similar manner. On the other hand, as is to be expected, for fixed ρ_w the production capacity decreases with decreasing well spacing, owing mainly to the decreased driving area at the water-oil contact. The increase of the capacity with increasing ρ_w may be simply interpreted as being due to the direct effect of increasing well radius or vertical permeability.

Simultaneous Production of Oil and Water

Although the above treatment is complete in showing the effect of such physical parameters as well penetration, oil-pay thickness, permeability, and well spacing on the water-free oil recovery, under the indicated assumptions, it is clear that from a practical point of view the later stages must be considered also where water is produced together with the oil. As Figs. 5 and 6 show, even after the water has reached the bottoms of the producing wells, there will, in general, still be a large part of the producing section saturated with oil. This will be especially true of the larger well-spacing developments. As operating experience has shown that frequently it is economically profitable to continue producing wells after the water-oil ratio has reached values even higher than 5 or 10, it is pertinent to consider the production characteristics of the wells after the water-free production stage has been passed.

As previously indicated, the method of analysis used in the treatment of this phase of the problem is based on the assumption that both the general and local rises in water table follow the same course after water has begun to enter the well as before. This in turn rests on the premise that there is no difference in the permeability to viscosity ratio between the region already flooded by water and that which is still saturated with oil. It will be supposed, therefore, that, even after the water has reached the bottoms of the wells, oil will continue to be displaced at a rate equal to the volumetric advance of the water zone, taking into account, of course, the microscopic flooding efficiency of the displacement mechanism, as represented by the factors *fd* in Eq. 5. At the same time, however, the wells will continue to produce a volume of total fluid at a rate equal to that of the oil before the water reached the wells. The difference between the latter rate and the rate of displacement of oil will then represent the rate of water production. By comparing this with the oil-production rate, the water-oil ratio is readily obtained.

The rigorous determination of the development of the water cut as production continues, even with the assumption mentioned, involves computations of the streamline distribution about the well and the sequence of water-oil interfaces representing the rising water table. These are fully described in the Appendix. The final results on the variation of the water-oil ratio with cumulative recovery are shown graphically in Figs. 9 and 10. The curves in Fig. 9 refer to "nonpenetrating" wells—which just enter the top of the producing section—and serve to show more directly the effect of the well spacing parameter $\bar{a}$.* In Fig. 10 are given the water-oil ratio curves for several partially penetrating well systems, and a spacing of 1.83 acres per well ($\pi\rho_e = 2$), and for two cases with 50 per cent penetration but well spacings of 7.31 ($\pi\rho_e = 4$), and 0.20 acres per well,

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* Actually, only the curve for $\bar{a} = 4$ was calculated by the method outlined in the Appendix. The remaining three were computed by an approximate method in which a functional form for the shapes of the water-oil interfaces was assumed, and its parameters were adjusted so that they satisfied certain necessary physical conditions.

($\pi\rho_e = 0.662$). The ordinates are the water-oil ratios of the composite water-oil flow stream, but not corrected for shrinkage effects. The abscissas indicate the state in the production history, expressed as a fraction of the total pay volume flooded by the rising water table, which is proportional to the cumulative oil recovery.

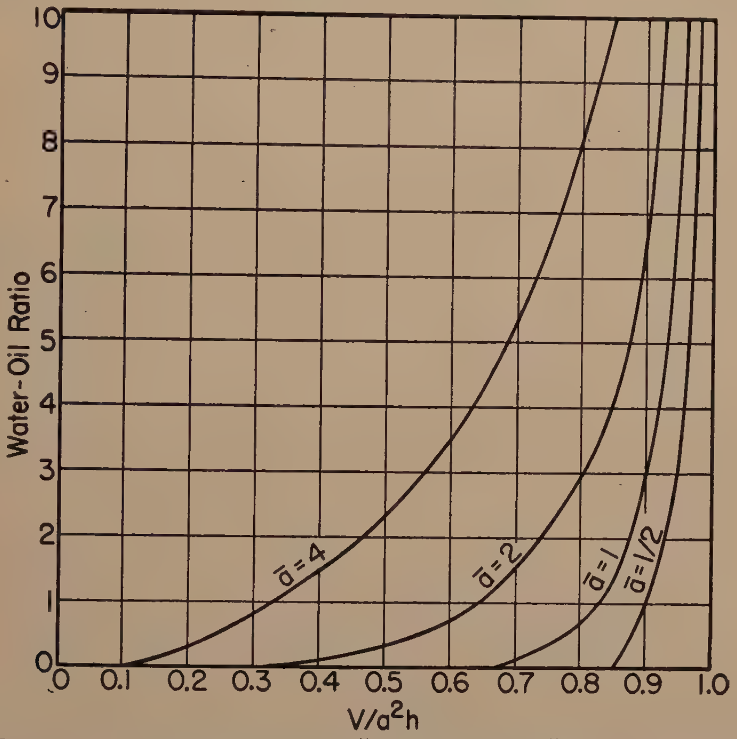

FIG. 9.—VARIATION OF WATER-OIL RATIO IN "NON-PENETRATING" WELLS WITH CUMULATIVE PRODUCTION, FOR FIXED WELL-SPACING PARAMETERS $\bar{a}$.

V = total volume of sand per well flooded out; a = well separation; h = thickness of oil pay.

As is to be expected, the abscissa intercepts in Figs. 9 and 10 represent the displacement efficiencies for the conditions defining the separate curves; for the abscissa units are just those of the displacement efficiency, defined by Eq. 1; and the assumption used for all the curves of Fig. 10 that $\rho_w = 0.001$* is equivalent to the requirement that $h\sqrt{k_h/k_z} = 125$, for a well radius of 3 inches.

As is to be expected, because of the natural asymptote to all such plots as in Figs. 9 and 10 at a unit abscissa value, the curves of Figs. 9 and 10 actually show a tendency for convergence in the region of higher V/a^2h. For fixed well penetration, both Figs. 9 and 10 show a quite rapid convergence among the curves for lower well spacings. For example, for the non-penetrating wells, the total oil recovery at a water-oil ratio of 5 will be only 11 per cent greater for $\bar{a} = \frac{1}{2}$ than for $\bar{a} = 2$ (a well density $\frac{1}{16}$ as great), whereas the water-free production will be 166 per cent greater with the former. Appreciable convergence to the lower well spacing systems has not yet developed at a water-oil ratio of 5 for the 50 per cent penetrating well with a spacing of 7.3 acres/well. However, the curves for spacings of 1.83 and 0.20 acres per well indicate a ratio of cumulative recoveries of approximately 1.06 at a water-oil ratio of 5, whereas the ratio of their displacement efficiencies is 2.89. Similar comparisons can be made with respect to the curves for different well penetration but the same well spacing.

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* It is this assumption which makes the values of ρ_e used in calculating the curves of Fig. 10 imply actual well spacings, in acres per well, which seem to be too close for practical interest. From previous results, however, it is to be anticipated that the character of the final curves would not be materially changed if ρ_w were taken as appreciably smaller, with a corresponding increase in the numerical equivalent in well spacings of the above values of $\pi\rho_e$ (cf. Eq. 12 of Appendix).

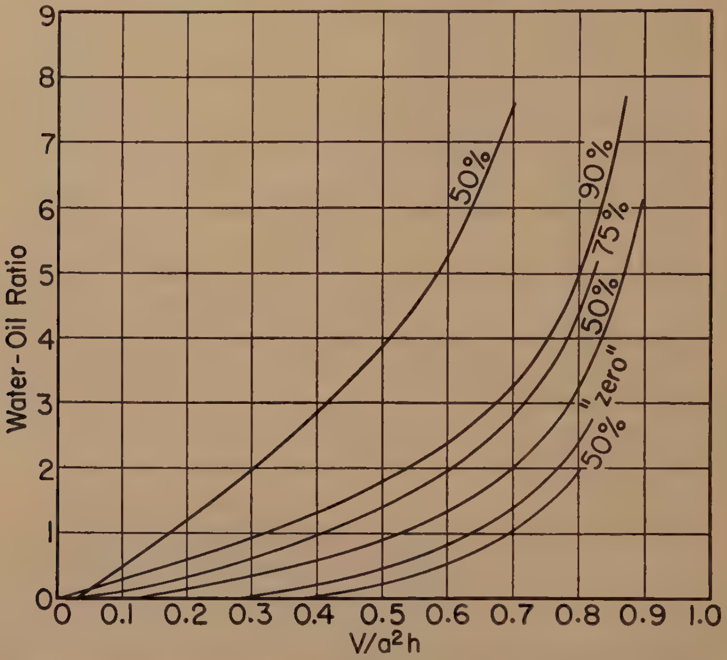

FIG. 10.—VARIATION OF WATER-OIL RATIO WITH CUMULATIVE PRODUCTION FOR PARTIALLY PENETRATING WELLS.

Numbers near curves indicate well penetration. For uppermost curve, the spacing = 7.3 acres per well; for next four curves, spacing = 1.83 acres per well; for bottom curve, spacing = 0.20 acres per well.

It thus appears that while close well spacings and low penetrations will give considerably greater clean-oil recoveries, the gains in ultimate recoveries, when limited by the rise in water-oil ratio to uneconomic values, will be much lower. In fact, an unqualified conclusion stating merely that the theory developed here shows that the recovery increases with decreasing well spacing would be decidedly misleading. On the contrary, it appears that, just as in gas-drive fields, economic factors will probably play the predominating role in ultimately evaluating development systems with different well spacings. For example, one must compare the value of the increased oil recoveries and cost of the lesser total volumes of water production,* for the smaller spacings, with the cost of the drilling and operation of the additional wells before any specific conclusion of economic significance can be drawn. And even without making such detailed comparisons, it is quite obvious that there will be an "optimum" spacing from the economic point of view. Certainly the value of the diminishing returns from continued increases of well density will ultimately be offset by the added investment costs, just as the savings in well investment will not compensate for the loss in oil recovery if the spacing is arbitrarily large.

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* These are given by the areas under the curves for water-oil ratio.

CONCLUSIONS

The theory developed here implies that *under the previously indicated assumptions* the behavior of wells subject to bottom water drives may be described as follows:

1. For moderate or minor degrees of anisotropy in the effective permeability of the oil pay the clean-oil production per well will be independent of the well spacing, within practical ranges of the latter. It will be proportional to the cube of the pay thickness and to the ratio of the horizontal to vertical permeability.

2. When the effective vertical permeability is much lower than the horizontal, the clean-oil production per well will increase with increasing spacing, although the total production before water entry from a given area will still decrease as the number of wells decreases.

3. The often observed persistence of clean-oil production for long periods of time—of the order of months or years—of wells produced by bottom-water drives with drawdowns much greater than the differential density head between water and oil indicates that the effective vertical permeabilities must be even much less, in such cases, than 1 per cent of the horizontal permeabilities.

4. The clean-oil production will decrease continually with increasing well penetration.

5. After the clean-oil production corresponding to the displacement efficiency has been recovered, water production will develop at an increasing rate. The water-oil ratio at a given cumulative oil recovery per well will increase with increasing well penetration and increasing well spacing.

6. As with the non-penetrating well, the nature of the rise of the water-oil interface under partially penetrating wells is not determined by the well spacing alone, but rather by a dimensionless parameter equal to the ratio of well separation to oil-pay thickness, multiplied by the square root of the ratio of the vertical to horizontal permeability.

7. As in the ranges of practical well spacings and physical parameters defining the producing system, the incremental increase in clean-oil production per additional well decreases with increasing well density, and, because of the limited gains in total economic oil recovery as the well density is increased, the optimum value of the spacing will be largely determined by economic considerations.

ACKNOWLEDGMENTS

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APPENDIX

POTENTIAL DISTRIBUTIONS

The basic analytical problem in the study of reservoirs producing by bottom water drives is the development of suitable potential distributions within the producing section that will satisfy the requirement of uniform potential over the well surface. For this purpose, a method developed some 14 years ago in the study of the production capacities of partially penetrating wells in strata bounded by impermeable formations[4] is used here. This involves the synthesis of the resultant potential distribution from elementary components corresponding to uniform flux densities extending along the well axis to various depths up to the total depth of penetration. The latter elements will satisfy the requirements of zero flow across the top boundry of the pay and uniform pressure at the bottom boundary; namely, the original oil-water contact. However, since these arise from uniform flux densities along the well axis, they will be characterized by variable potentials over the well surface. They will, therefore, be linearly superposed with suitable coefficients to give a resultant distribution over the well surface that is approximately constant.

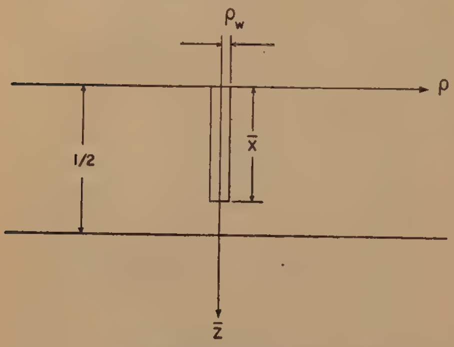

FIG. 11.—BOUNDARY CONDITIONS WITH NEW COORDINATES.

This problem may be formulated analytically as follows: Find a solution of the equation for the distribution of the potential Φ:

$$\left.\begin{aligned} k_h\left\{\frac{\partial^2\Phi}{\partial x^2}+\frac{\partial^2\Phi}{\partial y^2}\right\}+k_z\frac{\partial^2\Phi}{\partial z^2}&=0\\ \Phi=\frac{p-\gamma g z}{\mu}& \end{aligned}\right\}\quad [7]$$

with the vertical coordinate z directed downward, so that:

$$\left.\begin{aligned} \frac{\partial\Phi}{\partial z}&=0: z=0\\ \Phi&=\text{const}: z=h\\ \Phi&=\text{const. }(\Phi_w): z\leq b;\ r=r_w \end{aligned}\right\}\quad [8]$$

where h is the thickness of the oil-saturated zone above the original water-oil contact, b is the absolute well penetration, r_w is the well radius, γ is the oil density, μ is the oil viscosity,* p is the pressure, g is the acceleration of gravity, and k_h, k_z are the horizontal and vertical permeabilities. By taking the latter as unequal, one may treat from the start the case of anisotropic producing strata.

It will be convenient to reduce Eq. 7 to an equivalent isotropic system by the transformation:

$$z'=z\sqrt{k_h/k_z};\ h'=h\sqrt{k_h/k_z} \quad [9]$$

i.e., to the form:

$$\frac{\partial^2\Phi}{\partial x^2}+\frac{\partial^2\Phi}{\partial y^2}+\frac{\partial^2\Phi}{\partial z'^2}=0 \quad [10]$$

Moreover, we shall introduce the dimensionless coordinate system:

$$\begin{aligned} &\bar{z}=z'/2h'=z/2h;\ \bar{x}=b/2h;\\ &\rho=\frac{\sqrt{x^2+y^2}}{2h'}=r/2h';\ \rho_w=r_w/2h' \end{aligned}\quad [11]$$

In these new coordinates the boundary conditions will be (cf. Fig. 11):

$$\begin{aligned} &\frac{\partial\Phi}{\partial\bar{z}}=0: \bar{z}=0;\ \Phi=\text{const. }(0): \bar{z}=\tfrac{1}{2};\\ &\Phi=\text{const.}(\Phi_w): \bar{z}\leq\bar{x};\ \rho=\rho_w \end{aligned}\quad [12]$$

It may be shown that a solution of these equations satisfying the first two of Eqs. 12 and corresponding to a continuous and constant flux distribution extending from o to $\bar{x}$, will have a form at small values of ρ given by:

---

* As indicated in the text, it is assumed that these same parameters also apply to the region flooded out by the rising water table.

$$\left.\begin{aligned}
&\bar{z} < \bar{x}: \\
&\Phi = 2q\left[\log 4/\rho + \log \frac{\Gamma\left(\frac{\bar{x}-\bar{z}+1}{2}\right)\Gamma\left(\frac{\bar{x}+\bar{z}+1}{2}\right)}{\Gamma\left(\frac{\bar{x}-\bar{z}}{2}\right)\Gamma\left(\frac{\bar{x}+\bar{z}}{2}\right)} - \tfrac{1}{2}\log \tan \pi\,(\bar{x}+\bar{z})/2\right. \\
&\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad \left.\tan \pi\,(\bar{x}-\bar{z})/2\right] \\
&\bar{z} = \bar{x}: \\
&\qquad \Phi = q\left[\log 4/\rho + 2\log \frac{\Gamma(\bar{x}+1/2)}{\Gamma(\bar{x})} - \log \tan \pi\bar{x}\right] \\
&\bar{z} > \bar{x}: \\
&\quad \Phi = 2q\left[\log \frac{\Gamma\left(\frac{1+\bar{z}+\bar{x}}{2}\right)\Gamma\left(\frac{\bar{z}-\bar{x}}{2}\right)}{\Gamma\left(\frac{1+\bar{z}+\bar{x}}{2}\right)\Gamma\left(\frac{\bar{z}+\bar{x}}{2}\right)} + \tfrac{1}{2}\log \frac{\tan \pi\,(\bar{z}-\bar{x})/2}{\tan \pi\,(\bar{z}+\bar{x})/2}\right]
\end{aligned}\right\} \quad [13]$$

where q is the linear flux density, and Γ denotes the gamma function. For use at large values of ρ, the same solution may be expressed as:

$$\Phi = \frac{8q}{\pi} \sum_{\text{odd}} \frac{K_0(n\pi\rho)\cos n\pi\bar{z}\sin n\pi\bar{x}}{n} \quad [14]$$

where K_0 is the zero-order Hankel function.

If the well is a unit in a regular network of average spacing a, Eq. 14 may be generalized to the form:

$$\Phi = \frac{8q}{\pi} \sum_{\text{odd}} \frac{\cos n\pi\bar{z}\sin n\pi\bar{x}}{n} \left\{K_0(n\pi\rho) + \frac{I_0(n\pi\rho)K_1(n\pi\rho_e)}{I_1(n\pi\rho_e)}\right\} \quad [15]$$

where I_0, I_1 are the exponentially increasing Bessel functions of the third kind, and ρ_e corresponds to a boundary radius r_e defined by:

$$\pi r_e^2 = a^2 \quad [16]$$

The potential distributions along the well surface and below the bottom of the well to the base of the producing strata, as calculated by Eq. 15, have been plotted for a number of uniform flux elements and for $\rho_w = 0.001$ in Fig. 12. With a uniform flux density the potential at the well surface will decrease continuously with increasing $\bar{z}$, and will fall at the bottom of the well to values of the order of one half that at $\bar{z} = 0$. Such distributions will fail to satisfy the requirement of uniform potential along the well surface. Accordingly, it was assumed that the resultant potential distribution may be expressed as a linear superposition of individual terms of the type giving the curves of Fig. 12. That is, Φ was expressed as:

$$\Phi = \Sigma\, q_m \Phi_m(\bar{z}, \rho, \bar{x}_m) \quad [17]$$

where Φ_m denotes the potential distribution, as given by Eqs. 13, 14 or 15, due to a flux element of unit strength and extending to $\bar{z} = \bar{x}_m$, and the coefficients q_m were then determined so that the resultant Φ over the well surface was approximately constant. In carrying through this procedure it was found that to eliminate sharp fluctuations near the extremity of the well, with only a small number of values of $\bar{x}_m$, it was necessary to place at the extremity a differential flux element. The resultant* flux densities for $\rho_w = 0.001$, which were obtained by this synthesis process for various well penetrations and for wide well spacings, for which the additional series term in Eq. 20 could be neglected, are shown in Fig. 13. The numbers indicated in the parentheses are the relative strengths of the differential flux element placed at the bottom of the well. The values of Σ given with each distribution are a measure of the total resultant flux, and will enter later calculations, as will be seen below. The corresponding potential distributions over the well surface are plotted in Fig. 14. The integrated averages over the surface are indicated on these curves by the values of Φ_w. While the fluctuations in the well surface potential are quite evident in these curves, they should provide a good approximation to the mathematically rigorous solution in which the surface potential is strictly constant.

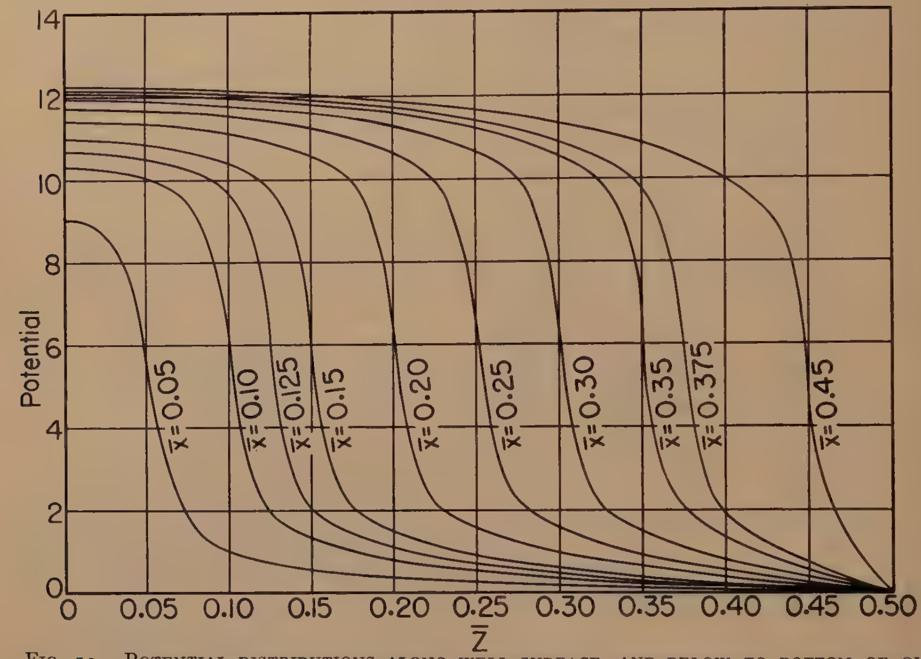

FIG. 12.—POTENTIAL DISTRIBUTIONS ALONG WELL SURFACE, AND BELOW TO BOTTOM OF OIL ZONE, IN BOTTOM WATER-DRIVE SYSTEMS, DUE TO UNIFORM FLUX ELEMENTS OF UNIT STRENGTH ALONG THE WELL AXIS.

$\bar{z}$ = (depth below top of oil zone)/(2 × thickness of oil zone); $\bar{x}$ = (length of flux element)/(2 × thickness of oil zone). ρ_w = dimensionless well radius = 0.001.

When ρ_e is less than one it is necessary to take into account the second term in the bracket of Eq. 15. The value of ρ_e may be expressed in terms of the well spacing by the relationship:

$$\rho_e = \frac{66\rho_w}{r_w}\sqrt{\frac{10A}{\pi}} \qquad [18]$$

where A is the well spacing in acres per well, r_w is the well radius in feet, which will be taken as ¼ ft. unless otherwise specified, and ρ_w is the dimensionless radius defined by Eq. 11. The corresponding value of the dimensionless distance between the wells, assuming that they are arranged in a square pattern of spacing a, is then given by:

---

* The discontinuous nature of the flux distribution shown in Fig. 13 is, of course, due to the small and finite number of terms used in the synthesis sum of Eq. 19, and should be visualized simply as a stepwise approximation to the actual continuous distribution.

$$\bar{a} = \frac{a}{h'} = 2\sqrt{\pi}\,\rho_e = \frac{132\rho_w}{r_w}\sqrt{10A} \qquad [19]$$

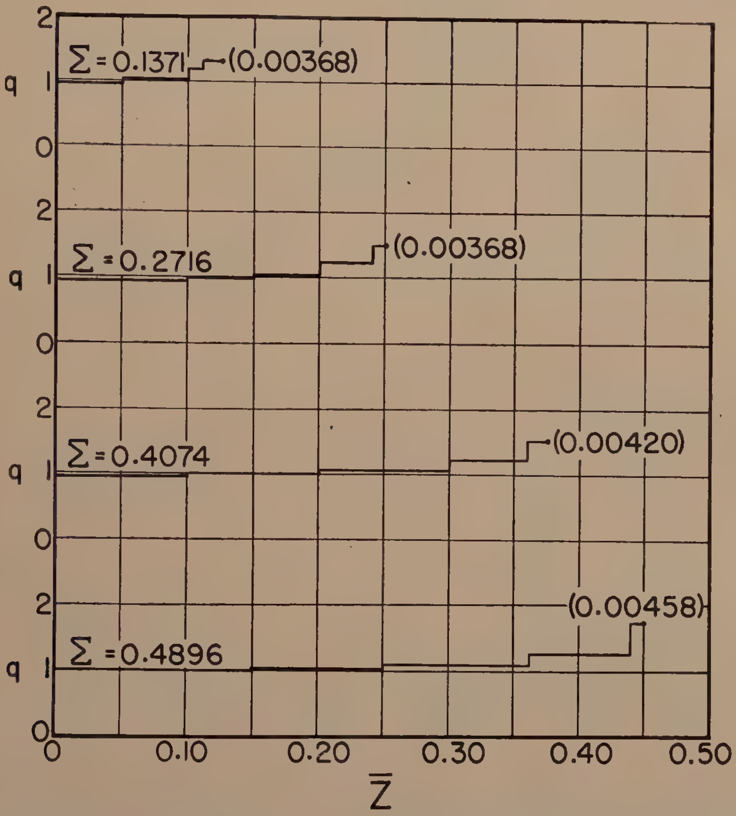

FIG. 13.—FLUX-DENSITY DISTRIBUTIONS ALONG WELL AXIS USED TO GIVE APPROXIMATELY UNIFORM SURFACE POTENTIALS FOR ρ_w = 0.001; q = RESULTANT LINEAR FLUX DENSITY.

$\bar{z}$ = (depth below top of oil zone)/(2 × thickness of oil zone). Numbers in parentheses indicate strength of differential elements at bottom of well. Σ is given by bracket of Eq. 22 in Appendix. Maximum value for individual plots of $\bar{z}$ represents well penetration in units of $\bar{x}$.

Taking into account the second term in Eq. 15, synthesis calculations were made of flux and potential distributions for a number of well penetrations for $A = 1$ and ⅕. For $A = 5$, the contribution of the second term in Eq. 15 was entirely negligible.

Production Capacities

The production capacities of the partially penetrating wells considered above may be readily obtained by evaluating the flux densities q_m in terms of actual flow rates. That for the individual flux element extending from $\bar{z} = 0$ to $\bar{z} = \bar{x}_m$, and of unit strength, is readily found to be given by:

$$Q_m = -2\pi k_h \int_0^b \left(r\frac{\partial\Phi_m}{\partial r}\right)_0 dz = -2\pi k_z \int_0^{r_e}\left(r\frac{\partial\Phi_m}{\partial z}\right)_h dr = 8\pi h k_h \bar{x}_m \qquad [20]$$

Similarly, for the differential element placed at the well extremity, the corresponding flow rate is:

$$Q_p = -2\pi k_z \int_0^{r_e} \left(r \frac{\partial \Phi_p}{\partial z} \right)_h dr = 8\pi h k_h \quad [21]$$

where Φ_p is the potential function for a differential element with unit strength.

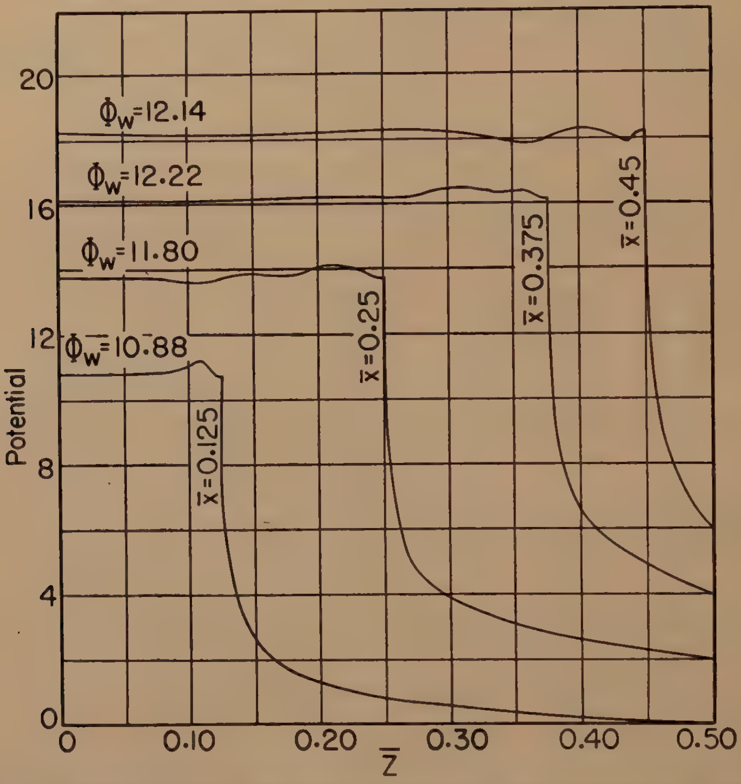

FIG. 14.—ADJUSTED POTENTIAL DISTRIBUTIONS OVER WELL SURFACE AND BELOW WELL BOTTOM FOR PARTIALLY PENETRATING WELLS, DEFINED BY $\bar{x}$, WITH DISTRIBUTED FLUX DENSITY SHOWN IN FIG. 13.

ϕ_w = average adjusted well surface potential.

The resultant total flow into the well is therefore:

$$Q = \Sigma Q_m + Q_p = 8\pi h k_h [\Sigma q_m x_m + q_p] \quad [22]$$

where q_p is the strength of the differential element.*

Now the potential functions Φ_m and Φ_p used above will all reduce to 0 at $z = h$, that is, the lower boundary of the oil-producing section. The total potential drop over the system is therefore the value of the average adjusted well-surface potential, denoted by Φ_w, and the numerical values of which are indicated in Fig. 14. It will also be recalled that these potential functions included the oil viscosity μ as indicated in Eq. 7. Hence in terms of unit actual potential drop across the oil section, and per unit total thickness and horizontal permeability, the production rate may be expressed as:

$$\frac{Q\mu}{2\pi h k_h \Delta\Phi} = \frac{4[\Sigma q_m \bar{x}_m + q_p]}{\Phi_w} = \bar{Q}_0 \quad [23]$$

or:

$$Q = \frac{0.007081 h k_h \Delta\phi \bar{Q}_0}{\mu} \text{ bbl. per day} \quad [24]$$

---

* The bracket in Eq. 22 is the quantity denoted by Σ in Fig. 13.

where h is expressed in feet, k_h in millidarcys, $\Delta\Phi$ in pounds per square inch, and μ in centipoises.

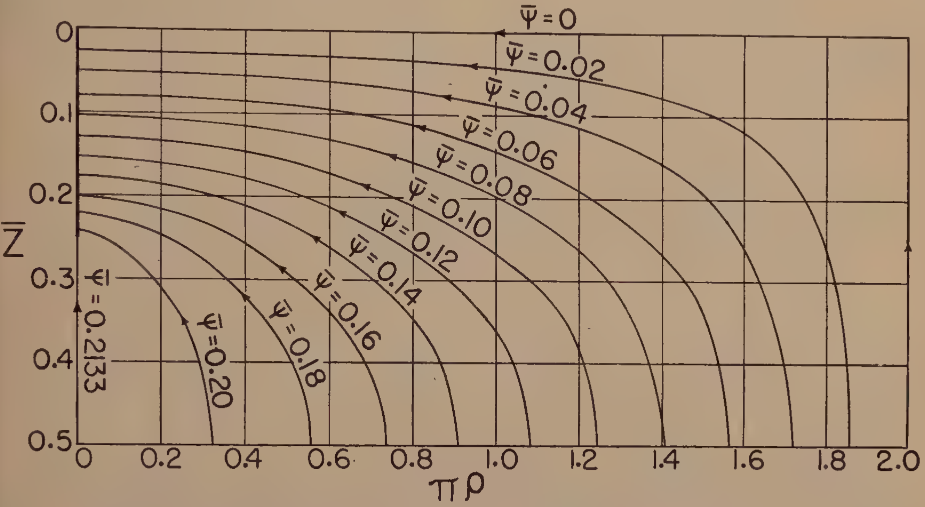

FIG. 15.—STREAMLINE DISTRIBUTION ABOUT A 50 PER CENT PENETRATION WELL WITH WELL SPACING OF 1.83 ACRES PER WELL AND $\rho_w = 0.001$.
$\bar\Psi$ = stream function defined by Eq. 30. Rest of notation defined by Eq. 11.

The values of $\bar Q_0$ calculated by Eq. 23 are plotted in Fig. 8, and discussed in the text.

Displacement Efficiency

The displacement efficiencies defined and discussed in the text were calculated as follows. The volume of oil flushed out by the time the water first reaches the bottom of the well may be expressed as:

$$\bar Q = Qt \qquad [25]$$

where t is the time taken for the water immediately below the bottom of the well to travel from its original position to the well extremity. This latter, in turn, may be expressed as:

$$t = \int_h^b \frac{dz}{v_z} = \frac{4h^2\bar f}{k_z}\int_{1/2}^{\bar x} \frac{d\bar z}{\dfrac{\partial\Phi}{\partial\bar z}} \qquad [26]$$

where v_z is the vertical linear velocity along the well axis, and $\bar f$ is the porosity of the oil section f times the fraction of the pore space displaced by the water flood; i.e. $f = f(1-\rho_w-\rho_{or})$, where ρ_w is the original connate water and ρ_{or} is the residual oil saturation after flooding.*

To determine the displacement efficiency, Eqs. 22 and 26 are combined as required by Eq. 25, to obtain the total volume of oil produced by the time of appearance of water. Applying then the definition of the displacement efficiency according to Eq. 1, we find:

$$E = \frac{32\pi}{\bar a^2}[\Sigma q_m\bar x_m + q_p]\int_{1/2}^{\bar x}\frac{d\bar z}{\Sigma q_m\dfrac{\partial\Phi_m}{\partial\bar z}} \qquad [27]$$

where $\bar a$ is the dimensionless well spacing defined by Eq. 2, and the sum in the integral is to include the contribution of the differential element at $\bar x$.

Defining the function F by:

$$F(\bar x, \bar a, \rho_w) = 32\pi[\Sigma q_m\bar x_m + q_p]\int_{1/2}^{\bar x}\frac{d\bar z}{\Sigma q_m\dfrac{\partial\Phi_m}{\partial\bar z}} \qquad [28]$$

---

* In the text $\bar f$ was separated explicitly as fd (*cf.* Eq. 5).

Eq. 27 may be rewritten as:

$$E = \frac{F(\bar{x}, \bar{a}, \rho_w)}{\bar{a}^2} \qquad [29]$$

As indicated in the text, the function F becomes essentially independent of $\bar{a}$ for $\bar{a} > 3.5$. The curves for the displacement efficiency as computed by means of Eqs. 28 and 29 are plotted in Fig. 9, and discussed in the text.

Streamline Distribution

As indicated in the text, to determine the nature of the water-oil interface and composition of the production after the water has broken into the producing wells, it is necessary to construct the streamline distributions. These distributions may be derived from the potential functions. Thus, corresponding to the potential function Φ given by Eqs. 15 and 17, the stream function Ψ may be shown to have the form:

$$\bar{\Psi} = \frac{\Psi}{32hk_h} = \rho\Sigma q_m \sum_{\text{odd}} \frac{\sin n\pi\bar{z}\sin n\pi\bar{x}_m}{n}\left\{K_1(n\pi\rho) - \frac{I_1(n\pi\rho)K_1(n\pi\rho_e)}{I_1(n\pi\rho_e)}\right\} \qquad [30]$$

with a similar equation for the contribution of the differential flux element.

Using such formulas, the stream functions (curves of constant $\bar{\Psi}$) have been calculated for several well penetrations and spacings. They are illustrated by those

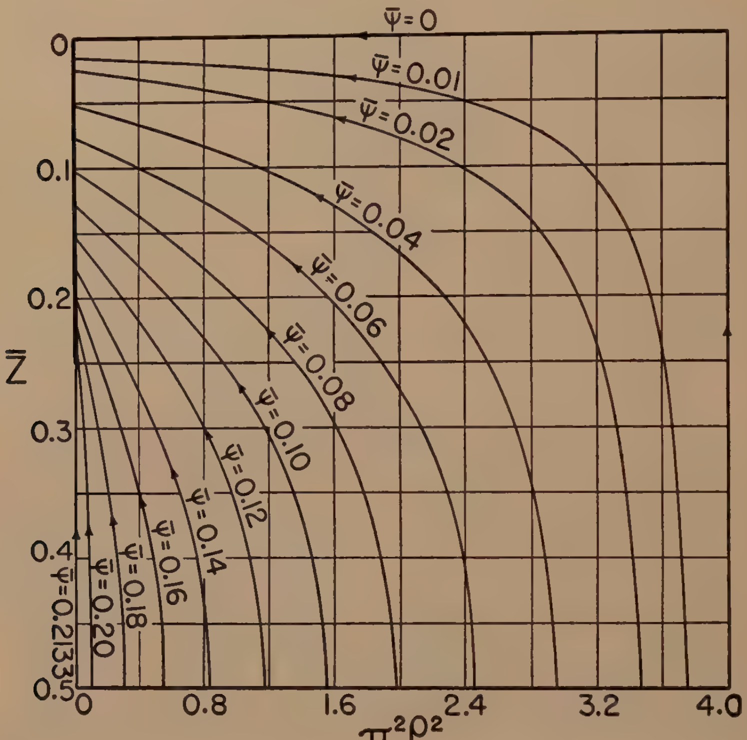

FIG. 16.—STREAMLINE DISTRIBUTION OF FIG. 15 PLOTTED IN ($\bar{z}$, $\pi^2\rho^2$) COORDINATE SYSTEM.

plotted in Fig. 15, for a 50 per cent well penetration with $\rho_w = 0.001$ and a spacing of 1.83 acres per well. The actual stream surfaces are evidently the surfaces of revolution obtained by swinging the plane of Fig. 15 about the well axis.

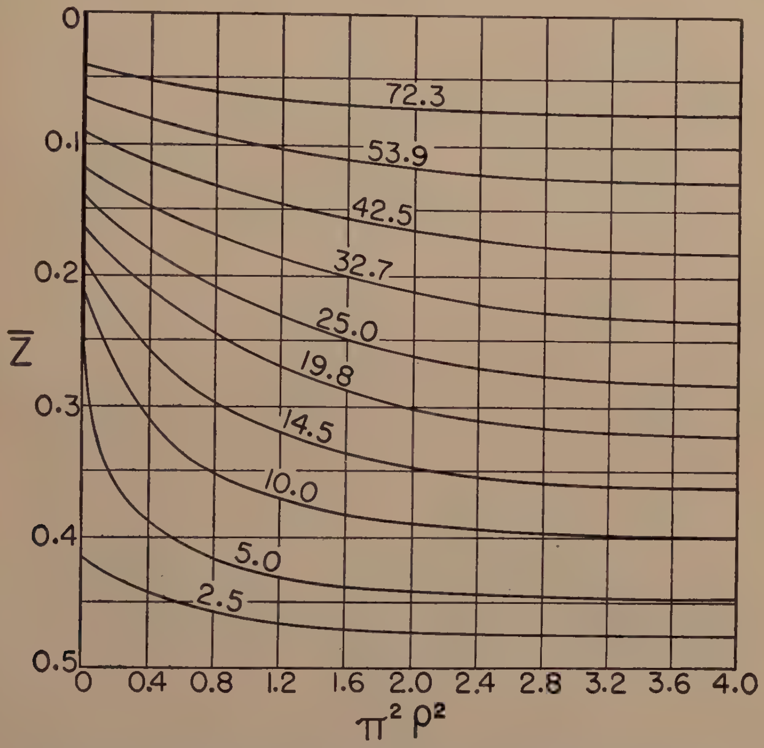

FIG. 17.—CALCULATED WATER-OIL INTERFACES FOR 50 PER CENT WELL PENETRATION, $\rho_w = 0.001$, AND WELL SPACING OF 1.83 ACRES PER WELL.

Coordinates are the same as in Fig. 16. ΔA = incremental area, proportional to time, in square centimeters as measured on the original streamline plots.

Water-oil Ratios

From the streamline distributions defined by Eq. 30 the composition of the production may be determined as follows: The time taken for a fluid particle, beginning at $\bar{z} = \frac{1}{2}$ (the initial water-oil contact) to reach any arbitrary level within the oil pay is:

$$t = \bar{f}\int \frac{ds}{v_s} \qquad [31]$$

where v_s is the volume flux along the streamline element ds followed by the particle. Taking note of the physical meaning of the stream functions Ψ or $\bar{\Psi}$,

$$t = \frac{\pi\bar{f}}{16hk_h}\int \frac{r\,ds}{\dfrac{\partial\bar{\Psi}}{\partial n}} \cong \frac{\pi\bar{f}}{16hk_h}\int \frac{r\,ds\,dn}{d\bar{\Psi}} = \frac{\bar{f}}{32hk_h}\frac{\Delta V}{\Delta\bar{\Psi}} = \frac{\bar{f}h'^2\Delta A}{4\pi k_h\Delta\bar{\Psi}} \qquad [32]$$

where dn is an element normal to the streamline, ΔV is the physical volume swept out by the particles lying on the original water-oil interface between $\bar{\Psi}$ and $\bar{\Psi} + \Delta\bar{\Psi}$, and ΔA is the area equivalent to ΔV, as measured on a plot of the streamline distribution and water-oil interfaces in a $(\bar{z}, \pi^2\rho^2)$ coordinate system. The streamline plot in this coordinate system, corresponding to Fig. 15, is shown in Fig. 16.

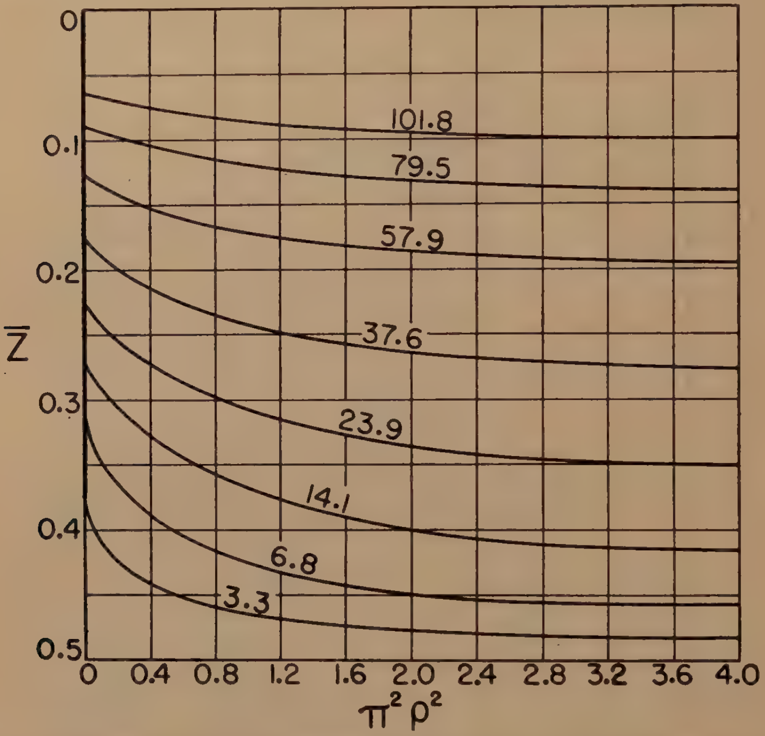

FIG. 18.—CALCULATED WATER-OIL INTERFACES FOR 75 PER CENT WELL PENETRATION, AND WITH REMAINING CONDITIONS AND NOTATION AS IN FIG. 17.

By planimetering the areas between the neighboring streamlines on such plots as Fig. 16, curves of constant ΔA or time were derived. These represent the water-oil interfaces, and are plotted in Figs. 17 to 20. The numbers associated with the individual interfaces give the values of ΔA in square centimeters as measured on original plots such as shown in Fig. 16, and are proportional to the time. While no claim is made for extreme precision in the detailed shapes of these curves, comparisons of Figs. 17, 18, 19 should indicate correctly the effect of well penetration, and of Figs. 17 and 20 the effect of spacing.

Now the rate of oil production is:

$$Q_{\text{oil}} = \bar{f}\,\frac{dV}{dt} = \bar{f}\,\frac{\delta V}{\delta t} \qquad [33]$$

where δV is the increment of volume swept out, between two neighboring water-oil interfaces, in the time δt.

Expressing δV in terms of an equivalent area δA measured on a $(\bar{z}, \pi^2\rho^2)$ plot, and δt by means of Eq. 32, Eq. 33 takes the form:

$$Q_{\text{oil}} = \frac{32hk_h\Delta\bar{\Psi}\delta A}{\delta\Delta A} \qquad [34]$$

If $\Delta\bar{\Psi}$ be expressed as a fraction β of the total range $\bar{\Psi}_{\max}$, we may write:

$$\Delta\bar{\Psi} = \beta\bar{\Psi}_{\max} = \frac{\beta Q_0}{32hk_h} \qquad [35]$$

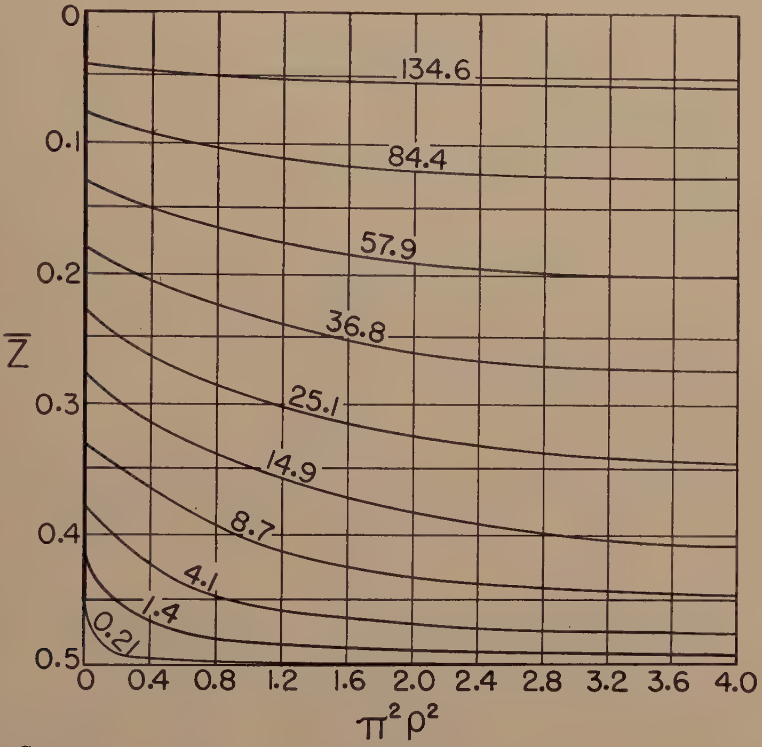

FIG. 19.—CALCULATED WATER-OIL INTERFACES FOR 90 PER CENT WELL PENETRATION, AND WITH REMAINING CONDITIONS AND NOTATION AS IN FIG. 17.

where Q_0 is the total flux rate $(Q_{\text{oil}} + Q_w)$ from the well. Combining Eqs. 34 and 35, it readily follows that the water-oil ratio R is:

$$R = \frac{Q_w}{Q_{\text{oil}}} = \frac{\delta\Delta A}{\beta\delta A} - 1 = \frac{1}{\beta}\frac{d\Delta A}{dA} - 1 \qquad [36]^*$$

Thus to get the water-oil ratio, one need measure only the slope of the curve of incremental area between neighboring streamlines ΔA, vs. the total area A, under the interfaces, multiply by $1/\beta$, and reduce by unity. The state in the flooding process associated with any particular value of the slope is defined by the value of A, which may be expressed in terms of the fraction of the total drainage volume swept out. The latter, in turn, is given by the ratio of A to the total area enclosed in the streamline distribution plot with coordinates $(\bar{z}, \pi^2\rho^2)$, as shown in Fig. 16.

A still simpler method for finding R is by use of the formula:

$$R = \frac{\bar{\Psi}_m - \bar{\Psi}_i}{\bar{\Psi}_i} \qquad [37]$$

where $\bar{\Psi}_m$ is the total range of $\bar{\Psi}$ over the whole system and $\bar{\Psi}_i$ is the value of $\bar{\Psi}$ at which the interface cuts the well surface. Again, the water-oil ratio so found is to be associated with the value of A, the area or volume under the interface whose well intercept is $\bar{\Psi}_i$.

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* As previously indicated, these fluid rates refer to reservoir conditions and must be corrected by the formation volume factors if applied to surface conditions. It may also be noted that Eq. 36 could have been derived directly from general considerations.

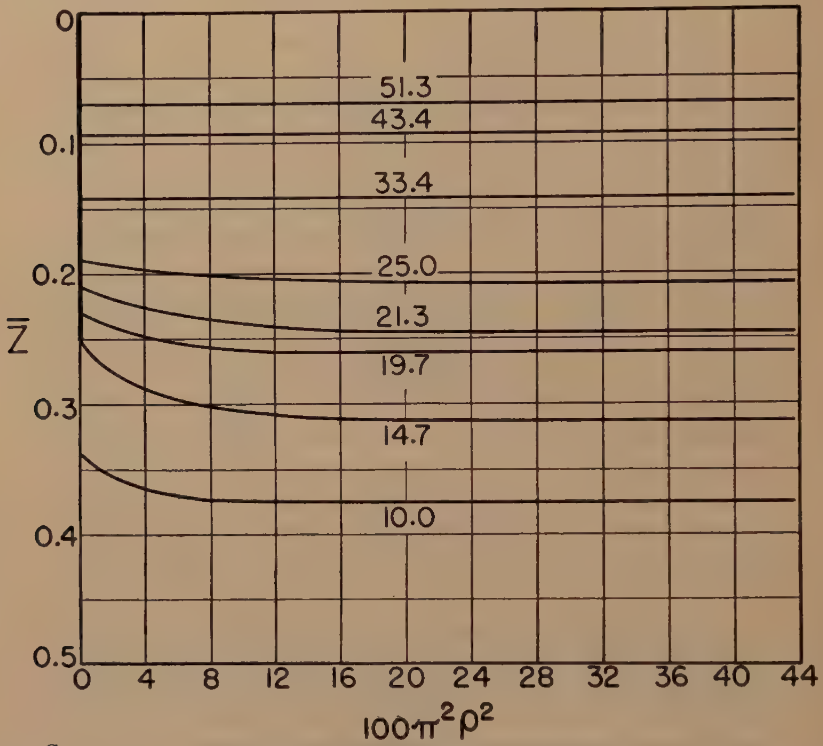

Fig. 20.—Calculated water-oil interfaces for 50 per cent well penetration, ρ_w = 0.001, and well spacing of 0.20 acres per well.
Remaining notation same as in Fig. 17.

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DISCUSSION

W. A. Bruce,* E. F. Johnson* and J. J. Mullane.*—It is of the utmost importance that every study of the fundamental principles upon which the performance of petroleum reservoirs depend be subjected to the most careful scrutiny in order to ensure that the assumptions and procedures used in the study are such as to yield results that are sound and that ≰ be of benefit to the industry.

This paper is a pioneering effort for which the author should be commended. It will be useful to others who may attempt further studies of the problem, but it is believed that, in order to obtain an analytical solution, the author has made assumptions that will lead to erroneous conclusions regarding the movement of bottom water into wells. There are occasions when simplifying assumptions can be justified in order to effect more readily a solution to a problem. In this instance, however, the assumptions made in setting up the problem are of such a nature as to render a solution to the problem of producing rates and well spacing in bottom-water drive fields that is definitely misleading and could lead to unsound decisions in the management of fields of this type.

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The most important technical criticism of this paper results from the author's failure to consider the difference in density between oil and water. Neglecting this density difference is equivalent to assuming in advance that the water cone is unaffected by rate of production or pressure drop in the well, but is a function only of total fluid produced. The author is clear in his acknowledgment that he has neglected the density differences; but he is not clear in his indication of the consequences of this assumption. Furthermore, owing to the complexity of the mathematical analysis, the magnitude of the errors that could result from this assumption are not readily apparent.

Water coning is a condition resulting from water being pulled into a well by a decrease of pressure at the well. As the cone is pulled up, the water is displaced from its normal position and there is a corresponding disturbance of hydrostatic equilibrium caused by water that has a higher density being above the lower density oil. If the flow into the well were stopped, the water-oil contact would again tend to level out. Thus the difference in density of the fluids and gravity tend to retard water coning.

The anisotropy of the porous permeable formation is the second important factor that retards the progress of a water cone. This anisotropy takes the form generally of lower permeability vertically than horizontally and comes about because of the nature of the sedimentation process when the rock was formed. It may be much greater over-all than individual horizontal and vertical permeability measurements would indicate.

Since no analytical treatment has been developed showing the magnitudes of the effect of these two major factors together, it is impossible to say which predominates. It would seem that, in low-permeability stratified sands, the anisotropy would predominate and that, in high-permeability, relatively homogeneous sands, the density difference would predominate. However, in the middle ground these two factors would be of comparable importance. The author has assumed arbitrarily that the entire effect of the delay in the rise of a water cone is due to the low vertical permeability.

It is evident that if one of these factors is ignored in an analysis of well behavior where the factors were comparable, the interpretation of the result would warp out of all proportion the inferred importance of the other factor. If a sufficient degree of anisotropy (high ratio of horizontal to vertical permeability) is assumed, it is possible to explain most observations of retarded water-cone rise. This does not mean that the theory is correct because the resulting ratio of permeabilities may be completely out of reason (for example, 10,000:1 instead of perhaps 10:1). If this ratio is moderate and the density difference is of comparable importance with the anisotropy, there will, of necessity, be some rate at which water will not be pulled into the well until there has been a rise in the average position of the water table to permit it.

Again the writers wish to commend the author for the presentation of an excellent analytical treatment of a very difficult problem. This criticism concerns itself only with hazards to be encountered in the application of this work to practical operating problems such as the determination of efficient producing rates or proper well-spacing programs for water-drive fields that are entirely or largely underlain by water. Specifically, it is believed that the author's theory can hold only in the limit of extremely low vertical permeabilities, and that as the ratio of horizontal to vertical permeability decreases the effect of the difference in density between oil and water, or gravity effect, becomes of ever increasing importance. This gravity effect, of necessity, will cause the production of water to be dependent upon pressure drop and producing rate.

L. F. ELKINS.*—In this paper there are two major assumptions that may be subject to criticism in applying the calculations to actual reservoir problems. The first of these is the neglect of gravitational forces, which Dr. Muskat pointed out was necessary for mathematical expediency and which applies in the reservoir only in the limiting condition where the operating pressure drawdown in the wells is large compared with the maximum difference in density head of the water and oil.

The second assumption that may be subject to criticism is that the pressure at the initial water-oil contact remains constant. I do not believe this necessarily follows from the assumption that the system is operating under steady-state conditions (which practically means a succession of steady-state conditions in the immediate oil-water reservoir as the general reservoir pressure declines). I believe that in a reservoir operating with a truly bottom water drive it would have been better to assume that the original pressure was maintained at a plane, say, one or two hundred feet below the original water-oil contact. For example, in a "nonpenetrating" well placed at 90 per cent penetration to the oil-water contact in a 25-ft. oil zone, an 11,150 ratio of horizontal to vertical permeability was necessary to obtain a 25 per cent effective displacement efficiency. The assumption of maintenance of original pressure at the original water-oil contact—only 2½ ft. below the well—causes an extremely large vertical pressure gradient to exist right below the well. I should like to ask Dr. Muskat what reduction in the degree of anisotropy would occur in one or two of the simpler examples if the plane of constant pressure were lowered to one or two hundred feet below the original water-oil contact.

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M. Muskat (author's reply).—The joint comments of W. A. Bruce, E. F. Johnson and J. J. Mullane, and those of L. F. Elkins, point out the neglect of the density difference between the oil and water in the analysis of the paper. This, of course, was explicitly listed by the author as an assumption, and its implications were pointed out. There is agreement about the qualitative nature of these. In fact, it seems that all the constructive remarks in these comments are simply those that were brought out with equal force in the last paragraph of the section of the paper, titled Assumptions. The differences pertain to the quantitative aspects of the implications; and, unfortunately, since the comments do not provide a quantitative evaluation of the effect of density difference, the disagreement apparently reduces to that of opinion, intuitive feeling, and "experience."

While the rigorous treatment of the effect of the density difference between the oil and water still remains an extremely difficult problem, and is one also left unsolved by the authors of the comments, an upper limit estimate of its effect may be obtained by comparing the pressure gradient at the original water-oil contact, as calculated in the paper, with the pressure gradient equivalent to the density difference. If the latter be taken as 0.3 gram per cubic centimeter the corresponding pressure gradient is approximately 3.10^{-4} atmo. per cm. For an oil-pay thickness of 25 ft. and "infinite" well spacing, the pressure gradient at the original water-oil contact ($\bar{z} = 0.5$) is found to be (corresponding to Fig. 14) $1.56 \cdot 10^{-3}$ atmo. per cm. for a 50 per cent well penetration and $13.7 \cdot 10^{-3}$ atmo. per cm. for 90 per cent penetration, if the total drawdown is 10 atmo. Even if the same relative magnitudes be assumed to apply to points removed from the well axis, and also to persist over the whole path along the well axis to the bottom of the well, the reduction in interface velocities and increases in volumes of clean oil production would amount to only about 20 and 3 per cent for the 50 and 90 per cent penetrations, respectively. Actually, however, only the differential effect of gravity between the well axis and remote points is of importance in flattening the water-oil interface. Moreover, the relative magnitude of gravity and pressure gradients will become smaller as the interface approaches the bottom of the well. And finally, while the effect of gravity will be greater at lower well penetrations and for greater pay thicknesses, it will be less at finite well spacings than for the infinite well-spacing example cited here. Under such conditions, which certainly could occur in practice, the neglect of the density difference could hardly be considered as grossly arbitrary and erroneous.

It thus seems that the conclusions and analysis of the paper will not in general be so restricted in validity as to be "misleading," except as that is a consequence of a misunderstanding of the explicit discussion in the text of the nature, reasons and implications of the assumptions. On the other hand, unfounded claims that any particular assumption vitiates a whole analytical structure, while at the same time admitting that "the magnitude of the errors are not readily apparent," may well create concepts regarding true reservoir behavior which are equally as misleading as blind faith in any assumptions, regardless of their nature. For example, in the case cited of a 25-ft. sand and 90 per cent well penetration with a drawdown of 150 lb. per sq. in., an observation of a displacement efficiency of 5 per cent, as defined in the paper, with a well spacing of 20 acres per well, would certainly imply a permeability anisotropy ratio of the order of 2000:1. And closing one's eyes to this fact under the pretense that the density difference has not been explicitly taken into account and the calculations are not rigorous may lead to misconceptions regarding the reservoir that may be far more serious than "misleading."

The joint authors of the comments appear to have missed the whole point of the analysis. The analysis itself includes the anisotropy ratio merely as a parameter just as the pay thickness and well spacing. It neither presumes nor pretends to assume or explain that all or even any specific practical situation actually has a high anisotropy ratio. That such is or may be true will develop only as an implication of a comparison between an observed displacement efficiency and those which would be theoretically expected with various assumed values of the anisotropy ratio. If the clean oil production has been obtained with drawdowns large as compared with the density-difference fluid head—by a comparison as outlined above—the anisotropy ratio corresponding to the observed displacement efficiency, whether high or low, will be substantially correct, whether or not it suits preconceived ideas. Of course, if the drawdowns are comparable to the density-difference fluid head, as may obtain in very permeable formations, similar calculations of the anisotropy ratio will give only upper limits, and such as may well be far too great. This, however, was fully recognized and stated in the text; namely, "Under such conditions significant differences in performance from that predicted here may well arise." A red light may indeed be misleading to one who is color blind, but the responsibility of obeying traffic signals by those of normal vision is not mitigated thereby.

Mr. Elkins' comment regarding the assumption of maintenance of the original pressure at the original water-oil contact is well taken. While the decline in average pressure at the original water-oil contact is in itself of little importance, except with regard to the effect of the gravity difference between the water and oil, the change in pressure distribution at the original contact due the flow into the well will lead to a modification of the details of the fluid motion. Accordingly, as suggested by Elkins, a calculation was made of the volume of clean oil production, under infinite well spacing, to be expected if the original uniform pressure were maintained at a depth of 144 ft. below the top of an oil pay, which, in itself, is only 40 ft. thick and is penetrated by a well to a depth of 36 ft. It was so found that the volume of clean oil production would be 2.9 times as great as if the pressure were considered as strictly uniform at the original water-oil contact. The maximum effect this could have on the inferred anisotropy ratio is a factor of 8.4, since an infinite well spacing was assumed in the calculation, still leaving the required ratio very high (or low) in many possible situations. And in finite well-spacing systems the correction factor may be considerably lower, if the corresponding $\bar{a}$ is appreciably less than 3. Moreover, a similar, though more approximate, calculation for an initial well penetration of 25 per cent (10 ft.) gave virtually no change at all in the clean oil production when the constant pressure surface was placed at a depth of 144 ft. below the top of the oil pay. It thus appears that while the effect suggested by Elkins may be quite significant in cases of high well penetration, it will not change the general broad implications of the theory developed in the paper.

Evaluation of Pressure Maintenance by Internal Gas Injection in Volumetrically Controlled Reservoirs

By E. Charles Patton, Jr.,* Junior Member A.I.M.E.

(Galveston Meeting, October 1946)

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ABSTRACT

A COMPREHENSIVE discussion is presented of a proposed method for utilizing the determinable basic physical facts about tight, volumetric-type reservoirs and their contained fluids, to arrive at the feasibility of injecting gas therein and to estimate the minimum amount of profit to be derived therefrom. A method is introduced for correlating laboratory relative permeability data with field performance history, and a method of relating the one to the other so as to enable predictions to be made of *future* performance based on past performance. This incorporates the substitution into the material-balance equations of a factor designed partially to take into account deviations from ideal behavior resulting from nonhomogeneity of the reservoir rock. The importance of this factor to the reliability of such predictions is not to be minimized.

A theoretical interpretation of the most nearly correct method of applying flash and differential laboratory data in their appropriate places in the material-balance equations, and a set of symbols to accommodate the distinction between these two different types of data is developed.

A set of equations for converting material-balance predictions directly to a time basis is given; a method of predicting the time at which the field economic limit will be reached, and a tentative method for predicting *relative* number of wells on the pump at any time under pressure maintenance as compared with primary performance have been described. These three concepts are prerequisites for the accurate evaluation of the economic benefits of pressure maintenance.

The equations and methods described may also be utilized to predict the relationship between gas-production rate and time to serve as a basis for design of proper size gasoline or compressor plant to accommodate an entire oil field, or to predict the most economically advantageous time to begin a gas-injection project.

The sale of residue gas in connection with the operation of a reservoir by natural depletion under some circumstances may prove economically superior to pressure maintenance by gas injection in spite of the expected increases in ultimate oil recovery by

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the latter type of operation. A situation such as this may arise from the interrelationship of the many physical and economic variables involved. Not the least of these factors are the magnitude of the savings due to deferred pumping as affected by the stage of depletion at which the proposed program is to be begun, and the relationship between the price of gas and the price of oil.

Although undoubtedly it would be next to impossible to make an absolutely accurate forecast of the future under any given program of operation, a means is provided herein for making a reliable prediction of the *relative* benefits of a gas-injection pressure-maintenance program as compared with normal depletion for a volumetric-type reservoir.

Introduction

In the early days of the petroleum industry little or no thought was given to efficiency of producing methods. Later, far-sighted operators experimentally pioneered new methods of increasing recovery efficiencies, some with quite beneficial results. Successful efforts along these lines led to laboratory investigations of the behavior of fluids contained in oil reservoirs and, at about the same time, to the development of a mathematical concept of this behavior, known as a material balance. Further laboratory investigation led to the development of acceptable theories relating to single-phase, and later to multiphase, fluid flow. Not until recently, however, were the fluid-flow concepts coordinated with the material-balance equations to the end that a method[1] was developed permitting the complete mathematical description of the reservoir pressure and gas-oil ratio behavior histories as functions of recovery in volumetric type reservoirs.

Other methods have been developed for predicting the future behavior of reservoir fluids under different operating conditions; for example, the Electric Analyzer[2] utilizes a small-scale electrical system and employs the analogy between the flow of current through the system and the flow of fluids within a reservoir to accomplish this end.

The principal problem of reservoir engineering is the prediction of a reservoir's performance under different methods of operation, and the economic interpretation of the results obtained to permit the selection of the optimum method of operation. Merely because a method of operation is feasible, purely from the standpoint of scientific principles, without regard to economics, it does not necessarily follow that such operation would be *economically* feasible. The *evaluation* of various methods of producing operation for the purpose of determining the feasibility of making changes in these methods is essential when accurate and certain conclusions must be made regarding the advisability of expenditures of large sums of money in this connection.

The problem of conservation of casinghead gases has gained wide import recently. Suitable markets for these gases have been lacking in various fields. Many operators have experienced increased oil recoveries from the injection of gas into underground oil reservoirs that have been depleted by primary methods. Because of the expected increase in oil recovery, the absence of a suitable market for their gas, and the deferment of the pumping stage, as a result of retarded pressure decline, many operators have given thought to the question of feasibility of injection of casinghead gas into oil reservoirs during the flush period. Various projects have been proposed involving the injection of gas into originally present gas caps overlying oil reservoirs, into the high part of the structure in oil reservoirs not containing original caps, for the purpose of artificially creating a cap, and directly into the oil-productive portions throughout an entire reservoir. Several such projects are already in operation.

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[1] References are at the end of the paper.

This paper is concerned with the latter, or internal type of gas-injection operation. The term "volumetrically controlled reservoirs" herein refers to reservoirs having no initial free-gas cap, operating primarily under solution-gas drive, and having an average absolute permeability to air of the order of from 2 to 20 millidarcys. The evaluation of the benefits of gas-cap injection may involve the assumption of gravity drainage, and under this assumption would require a slightly different approach than the present one insofar as the prediction of reservoir performance is concerned.

A mathematical treatment has been described in this paper whereby the gas-oil ratio, pressure, and production history can be computed for the types of operation under consideration, and whereby, once this history has been computed for *any* method of operation, these factors can be related to the time element. Relationship of these factors to time is often the governing factor in determining the feasibility of a gas-injection project.

Tarner[3] has shown that a delayed program of gas injection, whereby the pressure is allowed to decline normally to as low as about 300 lb. in some instances, and the same percentage of the "then future" produced gases is injected, may result in almost the same percentage of ultimate recovery increase as a similar program begun earlier in the life of a field. Occasionally this has given rise to the question of when to begin a gas-injection, pressure-maintenance program. As pointed out by Tarner, however, ultimate recovery is not the sole criterion. Oil-production rate, difference in operating cost due to deferred pumping, investment, relationship of price of gas to price of crude oil, availability of a market for residue gas, and many other factors can throw the economic balance one way or the other.

It must be borne in mind that large savings can be effected through deferred pumping operations from a gas-injection program begun early in the life of a field. Lack of an available market for casinghead gas, and the desirability of practicing gas conservation by avoiding the loss of gas to the air, have also influenced decisions for pressure-maintenance programs begun early in the life of some fields. Although the subject of when to begin such a program has not been discussed in detail herein, certainly the answer to the problem may be found through the application of the principles set forth.

Some of the material and methods introduced in this paper are new and some are quite conventional and have been in use for a long time. This paper is intended to combine what is thought to be the most logical attack on the various component problems to form a complete presentation of the attack on the major problem of prediction and evaluation. It presents all equations in such forms as to be usable directly with the consistent set of engineering units presented in the Nomenclature. The paper includes considerable detail in order to give an insight into the strengths and weaknesses of the various procedures employed, and in order to permit the procedures to be applied without the necessity of referring to the large number of technical articles in which such details must otherwise be found. Minor deviations from this specific method can be used to attack similar problems in other fields not falling into the same category.

Preliminary Examination

For Engineering Feasibility

If a gas cap is present in the reservoir under consideration, the possibility of gas-cap injection instead of internal gas drive should be investigated. Of course, if there are several operators in the field, unitization in this type of operation would be almost essential. Gas-cap expansion usually is thought to be superior to the internal gas expansion process unaccompanied by gas-cap expansion because, when accompanied by gravity drainage, usually it will lead to greater ultimate recovery, other things being equal. A high degree of gravity drainage normally requires steep dips, low oil viscosity and high permeability. Since the type of reservoir under consideration is of a low order of permeability, considerable structural relief and low viscosity would be desirable in order to take full advantage of gravity drainage. Muskat and Taylor,[4] however, have shown mathematically that without taking into account the additional benefit of gravity drainage usually thought to accompany gas-cap expansion, the mere presence of a gas cap that will provide additional free gas to expand through the oil zone tends to increase the ultimate oil recovery from a reservoir. This would be expected, inasmuch as the free gas from the gas cap in passing through the oil zone serves essentially the same purpose as the injected dry gas in the internal gas-injection process under consideration.

If there is some water drive indicated, the possibility of supplementing this by injection of water instead of gas should be considered. However, as in the previous case, reservoirs of the assumed low order of permeability under consideration are not usually accompanied by active water drives. It should be borne in mind, though, that two mutually contributing influences cause the relative advantage of water drive over gas expansion to be lessened with increasing values of interstitial water saturation. In the first place, Wyckoff and Botset[5] have shown relative permeability to water to increase with increasing water saturation, and Leverett and Lewis[6] have shown that relative permeability to oil is a function primarily of total liquid saturation. This means that the ultimate economic water-oil ratio under water drive will be reached sooner, and at a lower ultimate recovery value, if the interstitial water saturation is high. In the second place, Muskat and Taylor[4] have shown that the actual recovery by gas expansion will be greater for higher values of interstitial water. Therefore, if water injection is seriously being considered, the average value of the interstitial water saturation should be determined as accurately as possible by capillary methods, by cores taken with oil or oil-base mud, from electric logs, or by other methods. Erratic permeability distribution would probably be highly detrimental to the achievement of good results from pressure maintenance by water injection.

Adequate well interference data, supplemented if desirable by pilot injection-test data, can be interpreted to establish the continuity of the reservoir. If the reservoir is not continuous—that is, if it is composed of several alternating permeable and impermeable streaks, which themselves are more or less continuous—channeling may occur if gas is injected internally. If large cavities are present as a result of acidization in the majority of wells that might be used as injection wells, the possibility that packing-off attempts might be unsuccessful as well as the high cost of remedial work in this connection should be considered.

Collection, Preparation and Interpretation of Data

DATA NECESSARY

The data requirements for making an evaluation of pressure maintenance emphasize the importance of instituting, early in the life of a field, a systematic process for collecting accurate factual data.

The desirable data for making a study of this type are:

I. Analytical data
  A. Essential
    1. Core analyses from a representative number of wells
      a. Effective porosity
      b. Absolute permeability*
      c. Water content
    2. Hydrocarbon analyses
      a. Gas†
      b. Oil
    3. Gasoline content of produced gas‡
    4. Specific gravity† and hydrogen sulphide content‡ of produced gas
    5. Fluid behavior analysis§
      a. Solubility
        (1) Flash
        (2) Differential
      b. Relative oil volume
        (1) Flash
        (2) Differential
      c. Oil viscosity
  B. Supplementary
    1. Relative permeability K_g/K_o
    2. Relative permeability to oil K_o/K
    3. Capillary data on cores (for determining water content)
    4. Water analysis

II. Field data
  A. Essential
    1. Development-rate history (in partially developed fields)
    2. Abandonment history, if any
    3. Production history
      a. Oil
      b. Gas
      c. Water
    4. Pressure history
    5. Productivity index
    6. Gas-oil contact and oil-water contact (original and present)
      a. Drill-stem tests
      b. Production tests
      c. Electric logs
      d. Sample cuttings
      e. Electric pilot surveys
    7. Well interference data
    8. Average reservoir temperature
  B. Supplementary: Pilot Injection Test Data
    1. Field under study
    2. Similar fields

FACTUAL DATA

Isopachous Maps, Structure Maps, and Cross Sections

The data as usually collected are not in a suitable form for application in calculations for the field as a whole. One of the first requirements is the preparation of structure maps, isopachous maps, and cross sections. Structure maps and cross sections usually are essential to the preparation of isopachous maps. They contribute to the knowledge of the reservoir and to the interpretation of its behavior. Core data, electric logs, sample cuttings, electric pilot surveys, drill-stem tests, and production tests all may be used in determining the gas-oil and/or oil-water contacts and/or other vertical limits of the productive pay zone in individual wells. Core data, electric logs, sample cuttings, and electric pilot surveys are in turn used to eliminate the nonproductive portion between the vertical limits of the productive pay zone in each well, which thereby permits the determination of the number of feet of net permeable oil-productive pay. Preparation of these data is subject to a certain degree of latitude in interpretation.

If these data are available, the net isopachous map is drawn therefrom and planimetered, and the net acre-feet calculated. It may be desirable to planimeter each lease separately for possible use in the division of interests in the event of unitization.

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* Permeabilities to liquid phase are preferable, although such measurements are tedious to make. Permeabilities to air comprise the usual data available, and will serve the purpose.

† Either casinghead sample or trap sample, although former is preferable.

‡ Either casinghead sample or trap sample, although latter is preferable.

§ Either bottom-hole sample, or separator recombination sample.

Accumulative Oil, Gas, and Water Production

Data on oil, gas and water production should be accumulated by months, so that the accumulative production figures corresponding to each pressure survey can be readily ascertained. If more than one reservoir is present, accumulative production figures from the individual reservoirs should be maintained separately and each reservoir treated as a separate problem as far as possible.

Pressure

Original reservoir pressure, if not measured, should be estimated as accurately as possible in the light of early tests and pressure-production extrapolations in connection with bubble-point data. If an attempt is to be made to predict the past pressure performance from material-balance relations used in connection with the value of the oil in place, as determined by the volumetric method, it is more accurate for comparison purposes to weight the measured pressures. If the volume of oil originally in place is to be determined by material balance through the use of the measured pressures, then especially should the pressures be weighted.

The volumetric method is perhaps the most accurate method of weighting pressures. Volumetric weighting may be accomplished by drawing pressure contour maps and superimposing these upon isopachous maps and planimetering. This is very time-consuming, and less accurate methods often are employed. Aerially weighted average pressures, obtained by planimetering the pressure contour maps, are very reliable where the net thickness of the formation is relatively uniform. Simple arithmetical averages are not very accurate in tight formations.

If there has been very little decline from original pressure, any attempt to establish the value of the oil originally in place by material-balance methods would be hardly worth while.

Histories of Development Rate and Abandonment Rate

If the field is not completely developed, the complete history of the number of wells drilled each year and the cumulative total number of wells drilled should be tabulated and put in graphic form.

If any wells in the field have been abandoned, the number of abandonments each year, the cumulative number of abandonments, and the percentage of ultimate number of wells that have been abandoned should be tabulated.

Productivity Indexes

The accuracy of the reservoir-performance curves as a function of time will depend upon the degree to which the measured productivity indexes are representative of the entire reservoir. The percentage of total wells required for tests will depend upon the degree of variation of productivity throughout the reservoir and to some extent upon the actual ultimate number of completions. One study was made with productivity indexes measured on only 7 per cent of the ultimate number of wells in a field in which the normal range of variation in productivity indexes was about tenfold. A lower order of variation in productivity in another field permitted calculations that are believed to be reliable for the purposes of comparing pressure maintenance with primary recovery, which were based on measurements of still less than 7 per cent of the ultimate number of wells. Productivity-index data should be available on as many wells as is found practical, however. Two or more values on each of several wells, measured at different times and covering a span of a year or more, when available will be found desirable for checking the predictions of decline in productivity index.

Solubility and Relative Oil Volume

All results of fluid-behavior analyses should be inspected carefully and compared with results of producing gas-oil ratio and pressure measurements on the respective well at the time of sampling. From this inspection, samples not believed to be representative should be eliminated, insofar as interpretation of original bubble point is concerned.

Curves for flash and differential solubility and relative oil volume should be prepared as a function of pressure. There are arguments for and against the use of both absolute and gauge pressures in plotting these data. It will avoid confusion if the one selected is used consistently in plotting all data. For use in connection with the equations given herein, solubility should be expressed in terms of cu. ft./cu. ft.

Curves for the differential solubility and relative oil volume should be plotted first, because normal laboratory analysis usually gives data points throughout the entire pressure range for the differential liberation process. Assuming bottom-hole sample analyses from several wells in the same reservoir are available, either the solubility or relative oil-volume data may be averaged after plotting the data from each sample on the same graph. The value from each of the curves should be read and statistically averaged at each of several successive pressure points. These average values should then be plotted.

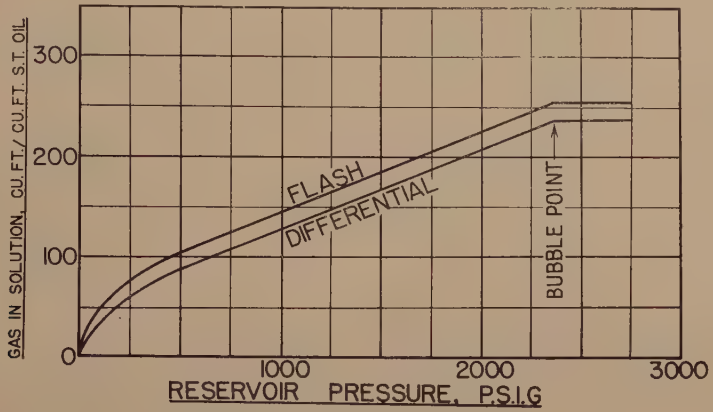

FIG. 1.—TYPICAL SOLUBILITY CURVES.

The average differential solubility may be determined directly by statistically averaging the differential solution ratio of each of the reliable samples. The pressure corresponding to this average solubility value on the average solubility-pressure curve should be the average bubble point.

If marked variations in bubble point occur with consistency throughout the reservoir, it might be desirable in predicting reservoir performance to treat the reservoir as several individual reservoirs, each with different bubble points, solubilities, and relative oil volumes. It would then be possible to make separate material balances for each, and integrate the results.

Flash solubility and relative oil-volume data should be based on separation at average separator pressure and temperature conditions in the field. The effect of small differences between the laboratory separator temperature at which the flash separation takes place and year-round average surface temperatures in most Mid-Continent fields can usually be neglected. This does *not* mean, however, that oil and gas-volume data are not corrected to a standard temperature and pressure base. Most laboratory analyses give flash data at several separator pressures. By plotting either the solubility or the relative oil-volume data for each bottom-hole sample against separator pressure, a value for that respective variable can be obtained from each sample at a predetermined field average separator pressure. These values for the given variable from all samples then may be averaged arithmetically, and plotted on the corresponding curve for average differential data versus pressure. The flash value should be plotted opposite the bubble-point pressure. The flash curve then should be drawn parallel to the differential curve through the one flash value thus plotted, until it reaches the vicinity of 500 lb. or less. By inspection it will usually be noted that the differential curve in this vicinity breaks away from the straight line and bends toward the pressure axis in order to reach the origin. For practical purposes, it can be assumed that the break in the flash curve will occur at about the same point. The two curves, of course, will completely converge at the origin. The U. S. Bureau of Mines laboratory usually runs a complete set of flash data from various saturation pressures, thus permitting the flash solubility and relative oil-volume curves to be drawn directly without reference to the differential curve.

Typical solubility and relative oil-volume curves are shown in Figs. 1 and 2.

Oil Viscosity and Gas Viscosity

Average oil-viscosity curves can be drawn in a manner similar to that by which average differential solubility and relative oil-volume curves are drawn.

Average gas viscosity should be determined and plotted as a function of pressure. This is done by first ascertaining the molecular weights of the various gas samples. If the specific gravities of the gas samples are reported directly, the molecular weights can be calculated from the following relationship.

$$\text{Molecular Weight} = 28.97 \times \text{specific gravity} \qquad [1]$$

If the densities of the gas samples are reported instead of their specific gravities, the following equations may be used:

$$\text{Molecular Weight} = 23.69 \times \text{density in grams per liter at } 60°\text{F. and } 14.7 \text{ lb. per sq. in. abs.} \qquad [2]$$

$$= 379.4 \times \text{density in lb. per cu. ft. at } 60°\text{F. and } 14.7 \text{ lb. per sq. in. abs.} \qquad [3]$$

If the specific gravities or densities of the gas samples are not measured or reported directly, the molecular weight can be determined from the hydrocarbon analyses by multiplying the mol fraction of each component by the corresponding molecular weight of that component and totaling. If direct measurements of specific gravity and fractional analyses are both available, the molecular weights from the two sources may be used as a check on one another. The molecular weights of heptane and all lighter components are given in Table 1.

TABLE 1.—*Molecular Weights of Heptane and Lighter Components*

Component	Symbol	Molecular Weight
Nitrogen	N_2	28.02
Methane	CH_4	16.04
Ethane	C_2H_6	30.07
Propane	C_3H_8	44.09
Isobutane	$i\text{-}C_4H_{10}$	58.12
n-butane	$n\text{-}C_4H_{10}$	58.12
Isopentane	$i\text{-}C_5H_{12}$	72.15
n-pentane	$n\text{-}C_5H_{12}$	72.15
Hexane	C_6H_{14}	86.17
Heptane	C_7H_{16}	100.20

The molecular weights of the various gas samples should be averaged arith-

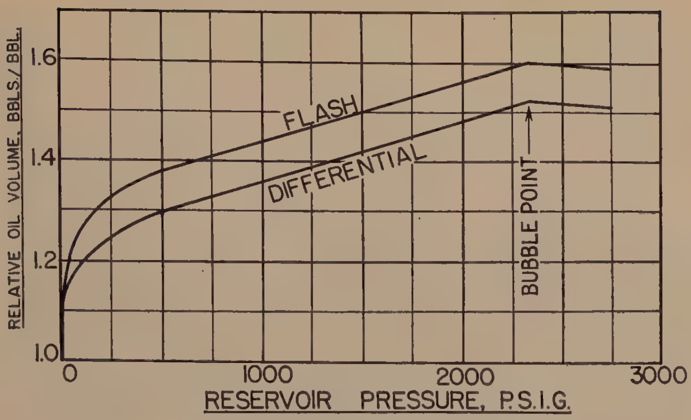

FIG. 2.—TYPICAL RELATIVE OIL-VOLUME CURVES.

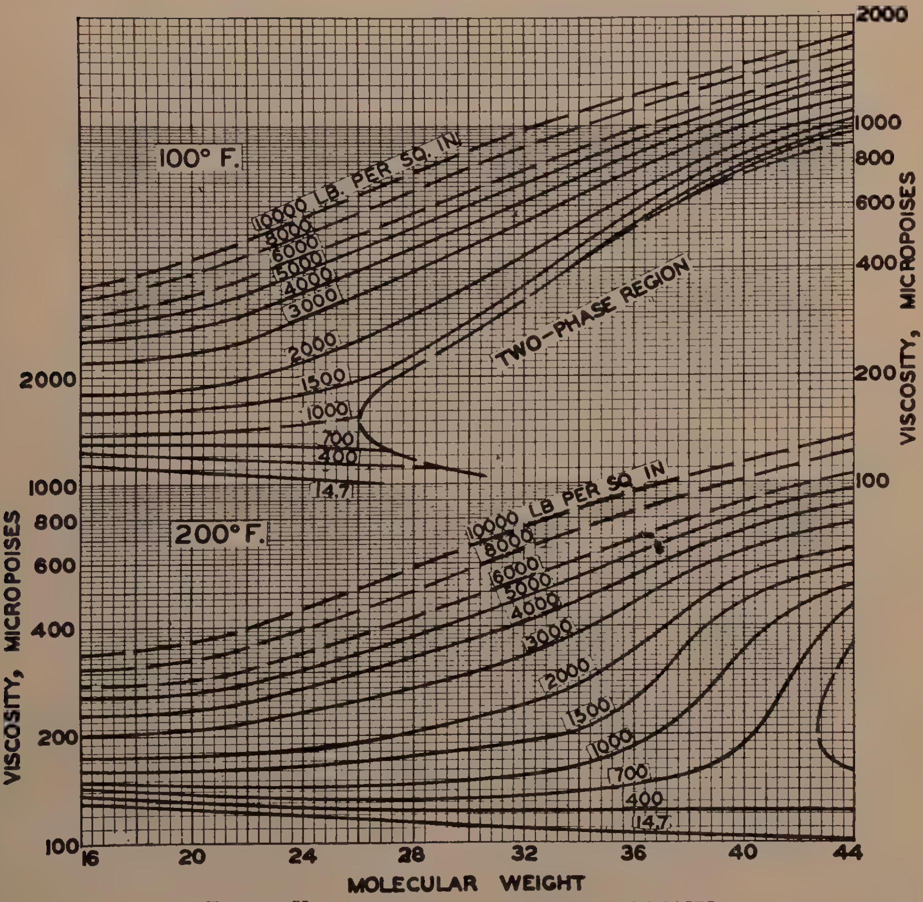

FIG. 3.—VISCOSITY VS. MOLECULAR WEIGHT OF GASES. *From Bicher and Katz.*[7]

metically. In some instances, if the fractional analyses are reported for all samples instead of molecular weights, densities, or specific gravities, it will be found easier to average the various analyses first and then compute the average molecular weight from the average analysis. From this average molecular weight and the average reservoir temperature, the average gas viscosity at several pressures can be interpolated from the curves of Fig. 3, after Bicher and Katz.[7] The average gas viscosity then should be plotted as a function of pressure.

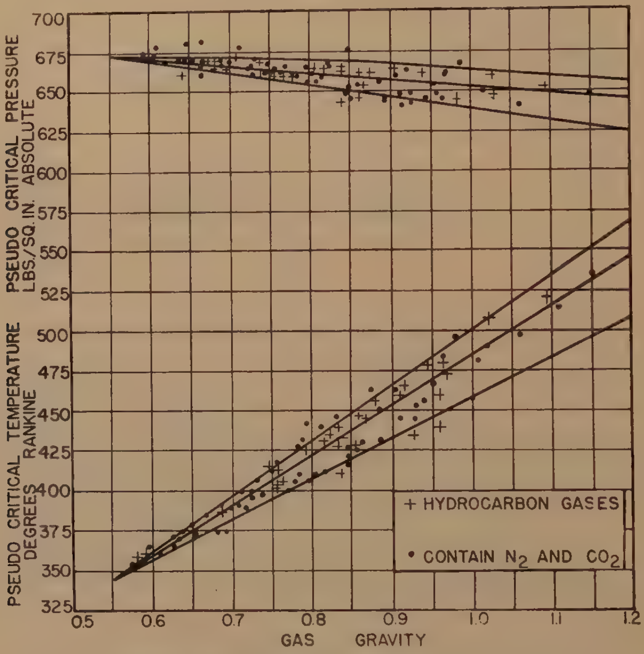

FIG. 4.—PSEUDOCRITICAL PROPERTIES OF 150 NATURAL GASES. *Reproduced by permission from paper by D. L. Katz.*[8]

In this method the assumption is made that the composition of the gas does not change with decline in reservoir pressure. This assumption is not strictly true; however, the change in composition makes such a small change in the viscosity, and since an *average* value of the composition must be used anyway, computation of the changes in composition with pressure decline for the purpose of making this correction would not be justified.

Gas-compressibility Factor Z

The gas-compressibility Z is sometimes called the "supercompressibility" factor. It corrects for the deviations from Boyle's law and is defined by the familiar relationships:

$$PV = ZmR''T \qquad [4]^*$$

or

$$\frac{V_b}{V_x} = f_x = \frac{P_x}{P_b}\left(\frac{460 + T_b}{460 + T_x}\right)\frac{1}{Z_x} \qquad [5]$$

In Eq. 5, subscript x denotes any specified reservoir conditions of pressure and temperature. See Nomenclature, at the end of the paper, for definitions.

The Z factor may be found at various pressures in the following manner:

The "pseudocritical temperature" is calculated from the average fractional analysis of the gas samples by multiplying the mol fraction of each component by the corresponding critical temperature of that component. These products are then added to give the "pseudocritical temperature." The "pseudocritical pressure" is calculated in a similar manner using critical pressures instead of critical temperatures.

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* R'' is used here to avoid confusing this with R in the material-balance equations.

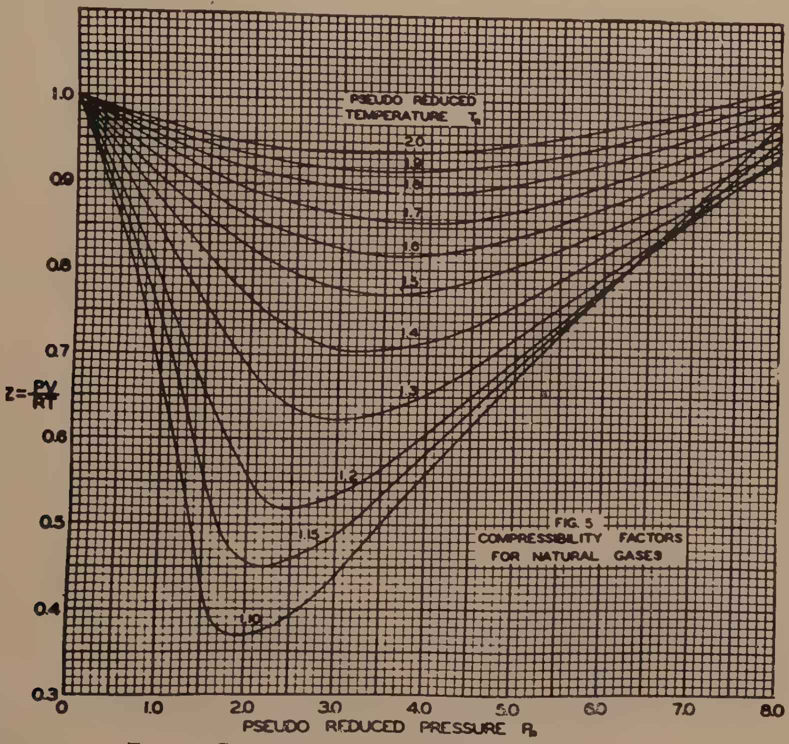

FIG. 5.—COMPRESSIBILITY FACTORS FOR NATURAL GASES.
Reproduced by permission from paper by Brown and Holcomb.[9]

If fractional analyses are not available, the approximate pseudocritical temperature and pressure may be found directly from the specific gravity of the gas by the use of the middle curves of the correlation, Fig. 4, reproduced from a 1942 bulletin of the N.G.A.A.[8]

The "pseudoreduced temperature" is then calculated by dividing the absolute temperature (degrees Rankine) by the pseudocritical temperature. The "pseudoreduced pressure" is similarly calculated by dividing the absolute pressure (psia) by the pseudocritical pressure.

The Z factor is then read from the curve, Fig. 5 (after Brown and Holcomb[9]) at the desired pressures by reading opposite the pseudoreduced temperature and the corresponding pseudoreduced pressure. The values of Z thus obtained are then plotted against reservoir pressure.

Critical temperature and pressure values of various components are given in Table 2 for use in this connection. There is a slight difference in some of these values as reported by various sources, but these differences are not significant as far as the accuracy required in this connection is concerned.

According to Messrs. Brown and Holcomb,[9] the volume of natural gas com-

TABLE 2.—*Critical Temperatures and Pressures*

Component	Symbol	Absolute Critical Temperature T_c, Deg. R	Absolute Critical Pressure P_c, Lb. per Sq. In.
Nitrogen	N_2	227	490
Methane	CH_4	343	673
Ethane	C_2H_6	550	708
Propane	C_3H_8	667	617
isobutane	i-C_4H_{10}	733	517
n-butane	n-C_4H_{10}	766	551
isopentane	i-C_5H_{12}	830	482
n-pentane	n-C_5H_{12}	847	485
Hexane	C_6H_{14}	915	434

puted in this manner is usually from 1 to 3 per cent too high unless the gas is nearly pure methane, or contains an amount of nitrogen or air approximately equal to the ethane, propane, and other heavier components. However, this method is sufficiently accurate without correction for the present purpose.

Specific Heat

Neglecting any correction for the presence of CO_2 or air, the specific heat at constant pressure for any gas may be determined from its fractional analysis by multiplying the mol fraction of each component by the specific heat at constant pressure of the respective component, and totaling. The specific heat at constant volume may be obtained in a similar manner. The specific heats of more important components, expressed in terms of British thermal units per pound per degree F., as quoted by the *Oil and Gas Journal* from the N.G.A.A. Standard No. 2145, are as listed in Table 3.

TABLE 3.—*Specific Heats*

Component	C_p at 14.696 Lb. per Sq. In. Abs.	C_v
Methane	0.526	0.402
Ethane	0.413	0.347
Propane	0.390	0.346
Isobutane	0.406	0.373
n-butane	0.396	0.363
Iso-pentane	0.413	0.387
n-pentane	0.402	0.376

SUPPLEMENTARY DATA

Major Development Area

Isopachous maps normally are drawn to include all acreage out to the zero isopach contour line. However, in fields of the type under discussion here, commercial wells usually cannot be drilled where the net productive pay is less than some minimum number of feet, depending upon several factors that vary from field to field (and from company to company), such as the well spacing, initial cost of the well, operating costs, overhead, royalty and overriding interests, average amount of recoverable oil in place per acre-foot, average initial productivity index, rate of productivity index decline, and curtailment of production. In partially developed fields the area inside the net isopachous line corresponding to this minimum number of feet may be referred to as the predicted "Major Development Area," abbreviated MDA. In other words, the limit of the Major Development Area is the line beyond which, for economic reasons, very few wells, if any, will be drilled. In some fields, depending upon structural conditions, this limit may make a marked difference in the oil in place and the calculated ultimate recovery as compared with the inclusion of all net productive acre-feet out to the zero isopachous line. For example, in one field the productive acreage to the zero isopachous line was reduced by more than 40 per cent when revised to include only the MDA. However, this structure had considerable relief, and as a consequence, the corresponding reduction in acre-feet was only about 20 per cent, which, however, corresponded to several million barrels estimated recovery.

The isopachous contour line corresponding to the limit of the MDA may be fairly accurately established before field development is complete. It is first necessary to compute the amount of oil that will have to be recovered by a well in order to "pay out" in the light of drilling costs, operating costs, time necessary to deplete the well, overhead, royalty, overriding interests, and other factors. From the material-balance work described later, the ultimate recovery expressed as a percentage of oil initially in place may be calculated. Working backward from the normal recovery calculations, as it were, the number of acre-feet can be calculated that, when multiplied by the computed recovery per acre-foot, will result in the necessary oil recovery required for a "pay out." From the well-spacing rules and the required number of acre-feet, the average thickness required is readily established.

In considering the oil in place inside the MDA, the question arises as to whether or not a substantial quantity of oil will drain into this area from the acre-feet that are excluded as being outside this line, and as to whether or not the average reservoir pressure within the MDA line will be affected appreciably thereby. For this reason, and because of the possible effect of less dense drilling around the fringe, it is well to choose an isopachous contour line slightly outside the one given directly by calculation. Pressure contour maps will reflect the rate and degree of attainment of pressure equilibrium and assist in establishing the MDA line more accurately for purposes of material-balance calculations wherein, actually, the MDA becomes the limit for establishing the volume of *effective* reservoir oil.

Stock-tank Oil Initially in Place

Oil initially in place, as measured under reservoir conditions, may be found by either the volumetric method or the material-balance method. If enough data are available for reliable determinations by both methods they may serve as a check on one another. The volumetric method follows the conventional procedure of multiplying the net acre-feet by 7758 to convert to barrels and then, in turn, multiplying by the average porosity fraction as determined from core analyses and by the difference between 1.00 and the average fraction of pore space saturated with interstitial water. Statistical average porosity and interstitial water values are preferable for use in this connection. This volume, as measured in the reservoir, is then divided by the relative oil volume (volume of reservoir oil per unit volume of stock-tank oil) to give the volume of stock-tank oil originally in place.

Relative oil volumes are measured in normal laboratory routine by two different processes, flash liberation and differential liberation. The flash-liberation process is one in which all of the gas remains in contact with the oil with which it was associated in the reservoir until it reaches the oil-gas separator. In the differential-liberation process, portions of the gas are liberated and removed from contact with the oil at successively lower pressures until the pressure is finally reduced to zero. It is generally conceded that the actual liberation process, which the oil and gas undergo from the well bore through the flow string to the field separator, is more closely simulated by the flash-liberation process, and that the actual process which the oil that remains in the reservoir undergoes, is more closely simulated by the differential-liberation process.

Since part of the oil initially in place undergoes more of a flash liberation and part of it undergoes more of a differential liberation, it would not be absolutely accurate to apply the relative oil volume as measured by either process, and to call the result "barrels of stock-tank oil initially in place," without qualifying as to the liberation process assumed in the conversion from reservoir barrels to stock-tank barrels. It will be seen later that in the method given herein certain simplifications are introduced by referring to this "volume of stock-tank oil initially in place" as the figure obtained through conversion by use of the relative oil-volume factor measured by the differential-liberation process. This procedure does not affect the recovery calculation, because in the basic material-balance equations the term "oil initially in place" is measured under reservoir conditions.

No very accurate method for the determination of the interstitial water saturation has yet been developed. Interstitial water is often called "connate" water—perhaps sometimes correctly and sometimes incorrectly. The total water saturation values, as found in cores at the surface, are usually in error because of flushing by drilling liquids, and/or loss of water through expansion of gas originally in solution in the water. Results of analyses of water content of cores taken while using oil-base mud or oil as a circulating liquid probably are fairly representative of actual reservoir conditions. Correlations between water content of cores of this type and cores taken in the same reservoirs with regular drilling liquids have aided in interpreting the true water content of reservoirs. The capillary method of determining reservoir water content apparently is fairly reliable in some cases, and in other cases appears to give results that do not correlate too well with other reservoir data. A method has been developed whereby interstitial water content can be determined from electric log resistivity curves.

Muskat and Woods[10] have pointed out that while material-balance methods cannot be used to determine accurate values for oil originally in place, size of original gas cap and water intrusion simultaneously, yet if any two of these three variables can be accurately established by other means a reliable determination of the third variable may be made by use of the material balance. Thus if substantial water influx is known to be nonexistent, and if the size of the gas cap, if present, is accurately determinable from geological methods, material-balance equations may be used to determine oil originally in place. Inasmuch as small differences in pressure normally result in correspondingly large differences in the calculated value of the oil in place, and since it is sometimes difficult in the type field under consideration to obtain accurate pressures from arithmetic averages, the results of these calculations based on such averages are often not too reliable. However, in some instances the results check remarkably well with those obtained from the volumetric method. The method consists of solving Eq. 9 herein for $O_2/{}_dF_2$ by trial balances with measured reservoir pressures and gas-oil ratios. As previously pointed out, the reliability of the results thus obtained may be improved greatly by volumetrically weighting either the pressures or the relative oil volumes and solubilities for pressure variations throughout the reservoir at any instant of time.

Forecast of Ultimate Number of Wells and Development Rate

If field development is incomplete, it is necessary to estimate the ultimate number of well completions in the field, and the number of new completions each year until the field is drilled up. The former may be estimated by dividing the total acreage inside the MDA by the average number of acres allotted per well. The latter forecast usually is made by extrapolating the development-rate history graphically to the predicted ultimate number of wells.

Relative Permeability K_g/K_o

This K_g/K_o term may be defined as the average ratio of the relative per-

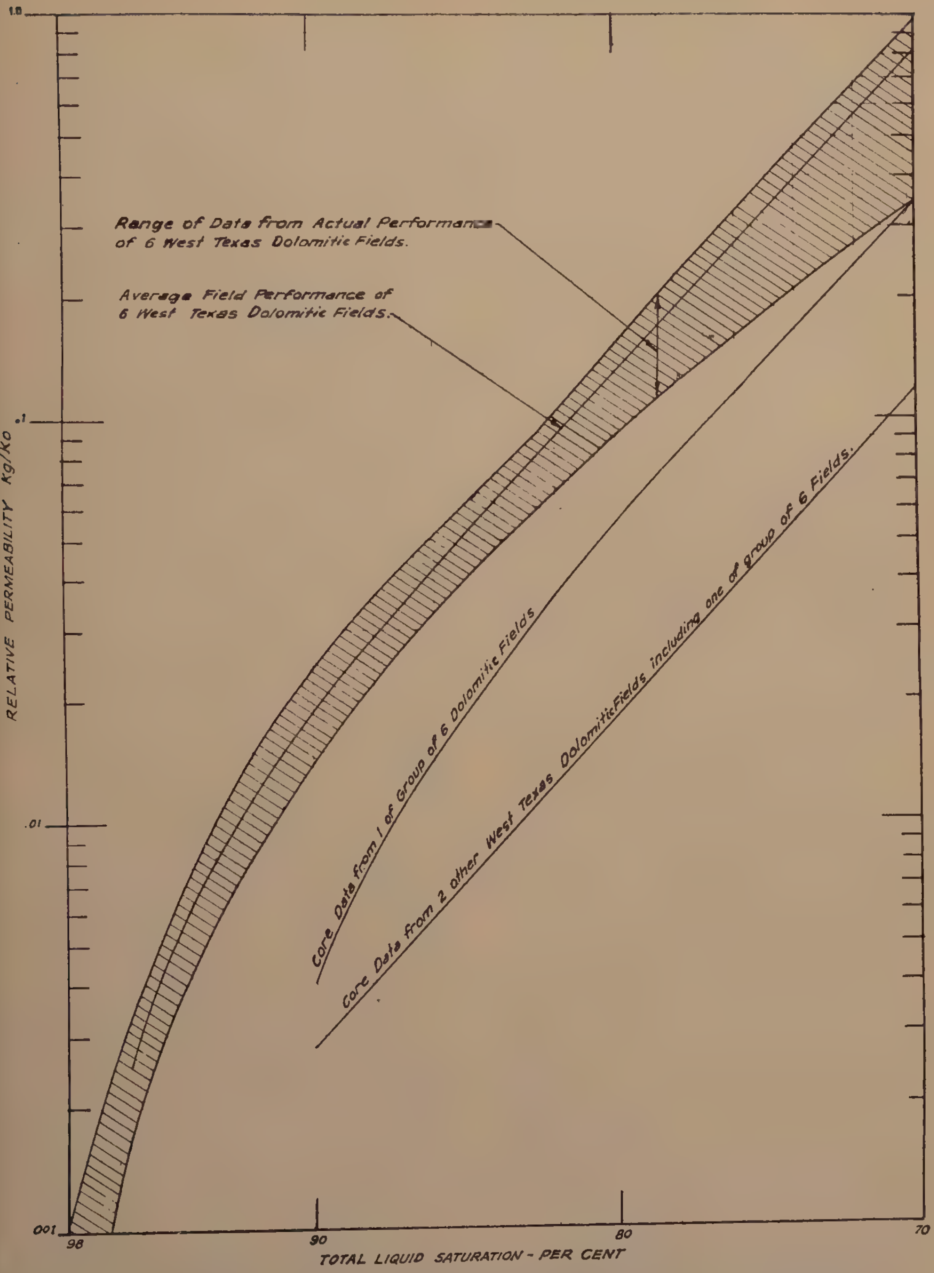

FIG. 6.—COMPARISON OF FIELD PERFORMANCE WITH LABORATORY DATA ON RELATIVE PERMEABILITY.

meability of the formation to gas to its relative permeability to oil at any given phase distribution.

Some work has been done by some of the major oil companies toward establishing the relationship between average reservoir liquid saturation and the K_g/K_o function from field performance data on several limestone and dolomitic-type reservoirs. The crosshatching in Fig. 6 shows an envelope within which the data from six separate fields fell. The curve within this crosshatching is the average of the six curves. The figure also shows that there was a wide discrepancy between this actual field performance data and laboratory data as measured on cores from three dolomitic-type fields, two of which fields were included in this group. No laboratory data were available on the other fields included in the envelope.

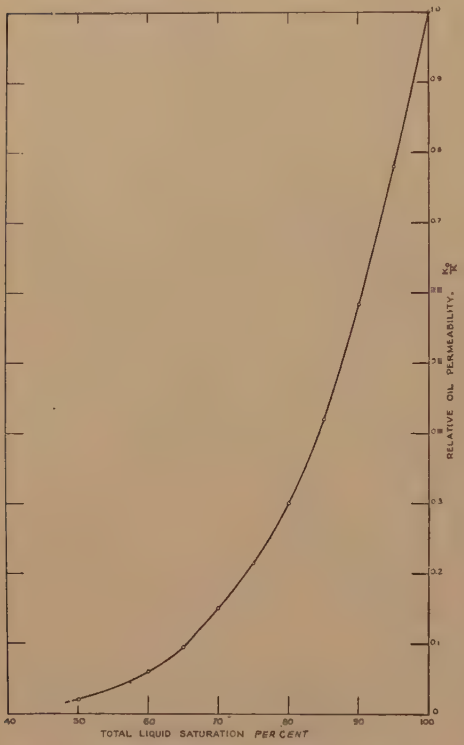

FIG. 7.—RELATIVE OIL PERMEABILITY VS. LIQUID SATURATION.
Dolomite core sample, no water present.

Muskat and Taylor[4] have shown that the ultimate recovery and performance of a reservoir are more sensitive to variations in the K_g/K_o curve at high liquid saturations than at low liquid saturations. If the field being studied is operating below bubble-point pressure, and if oil amounting to as much as 4 to 5 per cent or more of the pore space has been produced since the pressure fell below the bubble point, field performance data can be calculated to establish the K_g/K_o curve in this critical region of high liquid saturation. Eqs. 16, 24, and 25 (p. 24) may be used together with the appropriate field data to establish the K_g/K_o relationship. Otherwise, the curve representing the average of the six curves falling within the envelope of Fig. 6 should be sufficiently reliable to use for purposes of comparing pressure maintenance with primary recovery. A study of the work of Muskat and Taylor with regard to the effect of variations in the K_g/K_o curve indicates that the use of the average field performance curve of Fig. 6 in place of the actual performance of some hypothetical field represented by either the upper or lower limit of the crosshatching in Fig. 6 would result in very small errors in ultimate recovery or gas-oil ratio performance predictions. However, comparison of the K_g/K_o data used by Muskat and Taylor with those shown in Fig. 6 also indicates that the error in ultimate recovery or gas-oil ratio performance predictions resulting from the use of core data such as that shown in Fig. 6 (for primary recovery without the use of a conformance factor), when the actual field behavior followed some curve lying within the crosshatched area, would be quite significant. This divergence, in the critical region, is considerably more than the maximum divergence between the curves used by Muskat and Taylor, which resulted in a difference of 7.4 per cent in the calculated value of the ultimate oil recovery.

Relative Oil Permeability K_o/K

The statistical average K_g/K_o data, as determined in the laboratory on cores from one particular field included in the previously mentioned group differed markedly from field performance data on this same field. However, it was found by inspection of the relative permeability data on individual cores from this field that the values from one particular core sample duplicated, fairly closely, the average field performance data of the six fields that formed the envelope of Fig. 6. With slight adjustments, the K_g/K_o data from this sample were made to coincide even more closely with the average of the field performance curves. The curve for relative oil permeability resulting from this adjustment is presented in Fig. 7.

Assumptions

GENERAL

Broadly speaking, the complete evaluation of reservoir performance in its relationship to time as the problem is treated herein, involves the solution of the following simultaneous equations or sets of equations:

1. The material-balance equations, No. 10, No. 11 and No. 12.
2. The instantaneous produced gas-oil ratio equation, No. 15.
3. The liquid saturation equation, No. 23.
4. The multiphase permeability-saturation relationship.
5. The equation for productivity index decline, Eq. 31.
6. The oil-production rate equations, No. 35, No. 36 and No. 37.

The permeability-saturation relationship is handled graphically. The introduction of the time element into the prediction of reservoir performance, in itself, imposes additional requirements on the simultaneous solution of these equations, which are not directly accounted for by the oil-production-rate equation. These additional requirements imposed are:

7. Curtailment of oil-production rate to the current allowable for fields in prorated states.
8. Curtailment of gas-production rate when necessary to stay within some assumed plant capacity.

In order to meet all the foregoing requirements, a trial and error solution is almost essential.

In the simultaneous solution of the first three sets of these equations, a hypothetical, small differential element, or unit volume, of the reservoir is treated first. The permeability-saturation relationships determined from *average* reservoir performance histories of several fields of the type under consideration have been found to deviate only slightly from one another. Values from the average permeability-saturation curve thus obtained, together with average values of other properties of the reservoir rock, and average values of reservoir fluid characteristics are used in the treatment of the differential element of the reservoir. The future gas-oil ratio and pressure performance may thus be computed for this reservoir element as a function of accumulative oil recovery, expressed as a percentage of oil initially in place.

The performance may then be converted easily to a function of actual accumulative oil recovery by multiplying each percentage recovery value by the total volume of oil initially in place in the field. The results are then capable of being converted to a time basis through the use of the equations enumerated as items 5 and 6.

It is realized that in actual field performance, in some localized areas within a field, and in individual wells, wide deviations from calculated performance will undoubtedly occur. However, the problem herein is not concerned with localized phenomena, but rather with the *average* behavior of a reservoir, which should approximate the calculated performance before conversion to time rather closely, assuming the computations are based on accurate data.

The actual performance with respect to time may or may not follow the calculated performance, depending upon the possibility of unforeseen regulation instituted by man, as well as upon the accuracy of the data used in making the conversion to time. Here again, however, it should be emphasized that any such unforeseen contingency would probably have little or no effect upon the final answer; that is, the minimum *difference* in performance to be expected under the two methods of operation under investigation.

The mathematical treatment of the reservoir performance thus briefly described does not assume that any benefit will be derived from gravity drainage. Any benefit from gravity drainage that might occur under primary operations would tend to be increased under a gas-injection program, because of lower oil viscosity for any given recovery value. Assuming that this tendency is not entirely offset by the tendency for a lesser amount of gravity drainage corresponding to any given recovery value due to a lesser amount of time required to achieve this same recovery, any conclusion arrived at as to the feasibility of gas injection without considering gravity drainage would tend to be more thoroughly substantiated if gravity drainage did occur.

Major Assumptions

Conformance Factor

In deriving the equation for reservoir liquid saturation as a function of cumulative oil production under internal gas injection, the term "conformance factor" is introduced to represent the departure in field practice from uniform dissemination of the injected gas throughout the reservoir. Among the more important factors that cause this departure at any time from the ideal behavior of the injected gas are the lateral and vertical variations in permeability distribution, volume of gas returned to the reservoir and the rate thereof, ratio of the number of injection wells to the total number of wells, and the injection-well pattern. Perhaps the permeability profile is the most important of these factors. Failure to properly evaluate the conformance factor in relation to the permeability profile may result in misleading conclusions regarding the feasibility of pressure maintenance.

This conformance factor, therefore, allows for abnormal increases in gas-oil ratios resulting from unequal liquid saturation distributions throughout the reservoir incident to the injected gas moving through the more permeable zones and bypassing the tighter zones. It is assumed in the derivation of the equations applicable to gas injection that the tighter zones through which the gas does not move will behave exactly as they would under primary gas expansion, and that the increased recovery at any pressure will have resulted from a reduction in liquid saturation in the so-called "flow channels," which in turn causes an abnormal increase in gas-oil ratios.

This conformance factor, then, may be defined as the ratio of the net effective pore space, the saturation distribution of which has been affected at any pressure by the movement or presence of injected gas therein, to the total net effective pore space of the entire productive reservoir. The term is more concretely defined by the function it serves in Eq. 26 or the equivalent two equations, Nos. 27 and 28. Actually the value of the conformance factor may be different at different times during the depletion history. In the calculations an estimated average value for the life of the field usually is chosen and is assumed to remain constant throughout the depletion history.

One reason for the wide divergence, as exhibited in Fig. 6, between most laboratory data and field performance data on relative permeability may be that most laboratory data are measured at surface conditions of pressure and temperature. Some work has been done by at least one laboratory toward the improvement in equipment, whereby these variables may be incorporated into the measurements. Possibly if the correct conformance factor were known and applied to primary recovery, the K_g/K_o as calculated from field performance would agree more closely with the values as determined from core data. However, the results of the primary recovery prediction, based upon the correct statistical average K_g/K_o relation from core data and upon a conformance factor accurately established from the relationship between field data and core data for K_g/K_o, would be essentially the same as the prediction based entirely on field data for K_g/K_o without a conformance factor. A conformance factor calculated in this manner for primary recovery might serve as a guide for more accurately estimating the conformance factor to use for gas injection.

A visualization of the reservoir saturation condition analogous to that made under gas injection may also be made for primary operation. The reservoir under primary operation may be assumed to be divided into two reservoirs, each having different average liquid saturation values. The more permeable portions from which the oil is produced would correspond to the flow channels or e portion as defined for gas injection, and would have a lower liquid saturation at any time than the tighter portion corresponding to the $1 - e$ portion as defined for gas injection. Of course, actually, the average gas-oil ratio for primary recovery will be determined by the integrated effect of the innumerably different liquid saturations and K_g/K_o values existent throughout the reservoir at any time. However, inasmuch as, in this type field, there usually exist several permeable streaks through which most of the oil is believed to be produced, calculations based on the previous assumption may be of interest.

Knowing the average liquid saturation for the entire reservoir at any time, the average K_g/K_o for the entire reservoir from primary field performance data, and the relationship from core data between the statistical average K_g/K_o and liquid saturation, it is possible to calculate the three variables—average liquid saturation in the e portion, and in the $1 - e$ portion, and the value of e that, when used in connection with the statistical average K_g/K_o relation from core data will result in the average K_g/K_o for the entire reservoir from field performance—if any one of the latter three variables is arbitrarily fixed. Inasmuch as the liquid saturation in the $1 - e$ portion is higher than that in the e portion, the lower limit for liquid saturation in the $1 - e$ portion is fixed by the value of the average liquid saturation for the entire reservoir. The upper limit, of course, is 100 per cent. Calculations made on the basis of these assumptions indicate that the conformance factor under primary recovery for one of the fields included in the previously mentioned group is something less than 43 per cent, depending upon the degree of variation in saturation throughout the reservoir.

The introduction of the conformance factor into the equations is not believed to be necessarily the final answer to the amalgamation of theory with practice in connection with reservoir behavior. It is, however, one approach to the problem being attacked, and is considerably more realistic and conservative than the unadulterated use of the material-balance and gas-oil ratio equations in connection with the permeability-saturation relationship without any tie between theory and practice.

It is entirely possible, for instance (and there is some field evidence to indicate the possibility), that when gas is injected into an oil-saturated zone early in the life of that zone, before the gas saturation has reached the equilibrium value, the average permeability to free gas will be practically zero, and that, as a result, a "bank of oil" will be formed and forced ahead of the injected gas toward the producing wells. This would result in a radically different reservoir performance under gas injection than that which is described herein. As yet, however, there are insufficient data to prove that this actually takes place. If such an occurrence does take place, it would cause lower gas-oil ratios under gas injection than under primary operations and considerably greater increases in ultimate recovery, due to gas injection, than would result from the presently described approach. In this instance the approach described herein would lead to a very conservative answer.

Average Maximum Efficient Producing Pressure Differential MEPPD

The *MEPPD* is herein defined as 1/24 the maximum value of the product of the reservoir producing pressure differential times the number of hours during any one day that this differential can be maintained without abnormal increases in gas-oil ratio and consequent waste of reservoir energy. This *MEPPD* is used in determining future maximum efficient producing rates. This may be determined by field tests, although if a field is operating above the bubble point, the value of the *MEPPD* thus obtained will not reflect the true value, but will tend to be somewhat higher than the actual MEPPD that will be in effect when the reservoir pressure has declined below the bubble point.

One author[1] used a sand reservoir for an example, and for the purposes of calculating decline of productivity index assumed that the pressure differential gradually increased from 100 lb. per sq. in. initially to 320 lb. per sq. in. at a static pressure of 335 lb. per sq. in. However, for the purpose of evaluating pressure maintenance by gas injection, the usual assumption made for the type of reservoir under consideration is that the *MEPPD* will remain constant throughout the future life of the field.

Operating Assumptions

Optimum Compressor-plant Size

The optimum plant size can be calculated by a trial and error process, but the calculations are very lengthy. The usual procedure, after calculating the reservoir performance without regard to any plant limit, and converting to time, is, then, to assume two or three different plant sizes and recalculate the reservoir performance on each of these bases. After the economic balance is run on each of these, a good estimate of the optimum plant size can be made. However, if the object of the evaluation is merely to justify pressure-maintenance operations, and does not call for an evaluation of the exact optimum plant capacity, the recalculation can usually be made on the basis of merely one well-chosen plant capacity. A larger investment will be required to build a plant to carry the peak load, and this plant will be operating at full capacity for a shorter period of time than if a smaller plant is constructed. However, if it is assumed that no gas is vented or sold, this additional investment in the larger plant will tend to be offset by the reduced rate of gross income return with the small plant incident to the oil-production rate being retarded in order that the gas-production rate may stay within the limits of the plant capacity. The proper choice of compressor-plant size thus will hinge on the economic balance between the present net worth of the property with various plant sizes as influenced by the foregoing factors.

Number and Pattern of Injection Wells

The number of injection wells and their approximate location must be assumed in order to evaluate the production rate of oil and gas as a function of time and the cost of the distribution lines, respectively. As pointed out previously, the number and pattern of injection wells probably will influence the choice of the conformance factor to be used.

Allocation

In prorated fields the future allowable rate of oil production must be assumed, and this figure is then used in the conversion to time until the calculations indicate that the field will no longer produce this allowable.

Unitization or Cooperative Agreement

One or the other of the operating assumptions must be made for each evaluation. Unitization usually will result in certain savings in operating costs as a result of reductions in field operating personnel and equipment, and will permit better control of the entire operation.

Equations

BASIC MATERIAL BALANCE

The basic equation and some of the symbols developed by Alton B. Cook[11] are used herein with many additions and modifications. These basic material-balance equations are used because they lend themselves more closely than any other previously developed equations to the correct application of flash and differential laboratory data in their appropriate places.

Mr. Cook's basic equation using the symbols given herein is:

$$O_2 = \frac{\dfrac{G_x}{f_x} - \dfrac{S_x - S_s}{f_x}\,{}_{cf}N_x + {}_{cf}N_xF_x - J_2\left(\dfrac{f_2}{f_x} - 1\right) - W_{ex}}{\dfrac{F_x}{F_2} + \dfrac{S_2 - S_x}{F_2f_x} - 1} \qquad [6]$$

in which J_2 is here defined for the purpose of this equation alone as the "total volume of gas phase in the reservoir (measured at bubble-point pressure and reservoir temperature), cubic feet," W_{ex} is defined as the "net volume of encroached water in the reservoir at condition x, cubic feet," and S_x without a subscript *preceding* it is here defined as the *total* "volume of gas in solution, cubic feet of gas at 14.4 lb. per sq. in. and 60°F. per cubic foot of 'stock-tank' oil." The subscript s used in this equation represents separator conditions of pressure and temperature. In the Nomenclature (p. 38) as herein presented, a substitution is made for Mr. Cook's term "$S_x - S_s$," which represents the solution gas released from the reservoir to the separator per cubic foot of stock-tank oil at condition x. Either of the terms ${}_dS_x$ or ${}_hS_x$ as used in succeeding equations is identical with Mr. Cook's $S_x - S_s$ in the respect that neither includes the gas liberated between the separator and the stock tank.

As previously pointed out, the liberation process the oil undergoes in moving through the tubing and flow lines to the separator is most closely simulated by a flash-liberation process, and the liberation process undergone by the oil remaining in the reservoir is most closely simulated by the differential-liberation process.

The subscripts h and d, referring respectively to flash and differential processes of measurement of solubility and relative oil volume, are introduced directly into the equations herein in their appropriate places in accordance with the foregoing consideration. Thus the first term in the denominator of Eq. 6, when transposed to the left side of the equation represents the expansion of the total oil in the reservoir, which is primarily a differential process. The second term of the denominator transposed to the left side of the equation represents the total volume of gas released from solution in the reservoir oil at any pressure, which again has been primarily through a differential-liberation process. Likewise, the solubility and relative oil volume involved in the second and third terms of the numerator are most closely represented by a flash-liberation process. For these reasons, the solubility and relative oil-volume terms which are multiplied by the produced oil (N_x), should be designated flash liberation; and the solubility and relative oil-volume terms involving multiplication by the original oil in place at reservoir conditions O_1 or O_2 should be designated differential liberation. As previously pointed out, the latter assumption is not strictly true because part of the oil originally in place (that which is produced) does undergo both a flash and a differential process, the relative amounts of each depending upon whether the oil is produced early in the life of the field or subsequently. The integrated effect upon the total oil originally in the reservoir would undoubtedly be more of a differential than a flash process.

With the foregoing changes, and assuming no water influx and no initial free-gas cap, Eq. 6 becomes:

$$O_2 = \frac{\dfrac{{}_{cf}G_x}{f_x} - \dfrac{{}_hS_x({}_{cf}N_x)}{f_x} + {}_{cf}N_x \cdot {}_hF_x}{\dfrac{{}_dF_x}{{}_dF_2} + \dfrac{{}_dS_2 - {}_dS_x}{{}_dF_2 \cdot f_x} - 1} \qquad [7]$$

Important deviations in material-balance results in some instances may follow from not distinguishing between the two different processes of liberation. The magnitude of the deviation will be dependent upon the separator pressure and temperature and the compositions of the hydrocarbon fluids involved. Muskat and Taylor[4] have shown that important changes in ultimate recovery and reservoir behavior predictions result from systematically varying the formation-volume factor (and making the corresponding variations in solubility attendant to assuming a direct relationship between solubility and formation-volume factor) while holding the relationship between the other variables constant. Inasmuch as some difference between the flash and differential data usually exists, the data should be correctly applied.

Eq. 7 can be rearranged to become:

$$\frac{O_2}{{}_dF_2} = \frac{\left[\dfrac{{}_{cf}G_x}{{}_{cf}N_x} - ({}_hS_x - {}_h\mathrm{F}_x \cdot f_x)\right] {}_{cf}N_x}{({}_dS_2 - {}_dS_x) + f_x({}_dF_x - {}_dF_2)} \qquad [8]$$

which, by substitution, then becomes:

$$\frac{O_2}{{}_dF_2} = \frac{(R_x - C_x)}{I_x}\, {}_{cf}N_x \qquad [9]$$

where:

$$C_x = {}_hS_x - {}_hF_x \cdot f_x \qquad [10]$$

and

$$I_x = ({}_dS_1 - {}_dS_x) - f_x({}_dF_2 - {}_dF_x) \qquad [11]$$

If $O_2/{}_dF_2$, which refers to the bubble-point condition, is assumed to have a value of 1, Eq. 9 becomes:

$$\frac{(R_x - C_x)}{I_x} N_x = 1 \qquad [12]$$

and the solution of Eq. 12 for N_x by trial balances at successive pressures to depletion will give N_x values in terms of the fraction of original "stock-tank" oil in place at the bubble point that has been produced from bubble-point pressure to the reservoir pressure at condition x. (Assuming the "stock-tank" oil originally in place at the bubble point to be defined by $O_2/{}_dF_2$, this means, as previously pointed out, that the conversion from reservoir to stock-tank conditions should be made by differential liberation for the purpose for which this term is used herein.) For any assumed pressure, the values C_x and I_x will remain constant while different values of N_x are assumed and trial balances are made until Eq. 12 is satisfied.

As previously pointed out, in applying Eq. 12 to an entire reservoir the assumption is made that equilibrium conditions exist throughout the reservoir at all times. Such an assumption is known not to be true, but for the purpose of comparing pressure maintenance with primary recovery, and in view of other contingencies perhaps more significant than this, such an idealized behavior assumption is justifiable.

The calculation of N_x values as a fraction of the stock-tank oil originally in place at the bubble point permits easy revision of recovery calculations resulting from geological revisions or other changes affecting the estimated value of the oil originally in place.

Gas-oil Ratio

In order to substitute the term R_x (cumulative net gas-oil ratio) in Eq. 12, the instantaneous gas-oil ratio r_x must be evaluated at each successive pressure.

Leverett and Lewis[6] in their basic work on relative permeabilities state that the "free gas-oil ratio" flowing in a sand is equal to:

$$\frac{K_g}{K_o} \cdot \frac{U_o}{U_g} \qquad [13]$$

Measured at the surface, this "free gas-oil ratio" would be equal to:

$$\frac{K_g}{K_o} \cdot \frac{U_o}{U_g} \cdot f \cdot {}_hF \qquad [14]$$

The producing gas-oil ratio r_x, measured at the surface at any time, condition x, is equal to the sum of the solution gas-oil ratio plus the free gas-oil ratio, or

$$r_x = {}_hS_x + \frac{K_{gx}}{K_{ox}} \cdot \frac{U_{ox}}{U_{gx}} \cdot f_x \cdot {}_hF_x \qquad [15]$$

Fancher[12] has given the preceding equation in only slightly different form. For purposes of actual calculation and tabulation of results it may be found advantageous to put Eq. 15 in the form of four equations, as follows:

$$r_x = {}_hS_x + B_x \cdot K_{gx}/K_{ox} \qquad [16]$$

$$B_x = Y_x \cdot f_x \cdot {}_hF_x \qquad [17]$$

$$Y_x = U_{ox}/U_{gx} \qquad [18]$$

$$f_x = \frac{520}{(460 + T_r) \cdot P_b} \cdot \frac{P_x}{Z_x} \qquad [19]$$

As in the case of C_x and I_x, for any assumed pressure, the values of f_x, Y_x and B_x remain constant while different values of N_x are assumed and trial balances are made until Eq. 12 is satisfied.

After the instantaneous gas-oil ratio r_x has been determined at any subsequent pressure (condition x), the average of the instantaneous gas-oil ratios for the period from the previous condition $x - 1$ to condition x is evaluated by the equation:

$$r'_x = \frac{r_x + r_{x-1}}{2} \qquad [20]$$

The gas produced during the pressure period immediately preceding condition x may be approximated by:

$$\Delta G_x = G_x - G_{x-1} = r'_x(N_x - N_{x-1}) \qquad [21]$$

The cumulative net gas produced to condition x is:

$$G_x = \Delta G_x(1 - i) + G_{x-1} \qquad [22]$$

where i is the fraction of the produced gas being returned to the reservoir.

Liquid Saturation

In order to substitute approximate values of the K_g/K_o function in Eq. 16, it is necessary to know the liquid saturation at any time (condition x). A different equation is used for primary recovery than for internal gas injection. For primary recovery, a straightforward derivation for the liquid saturation at condition x results in the following equation:

$${}_pL_x = {}_pA_x\left[1 - {}_pN_x \cdot \left(\frac{{}_hF_2}{{}_dF_2}\right)\right] + S_i \qquad [23]$$

where

$${}_pA_x = \frac{{}_dF_x}{{}_dF_2}(1 - S_i) \qquad [24]$$

The substitution of ${}_{d}F_2 = {}_{h}F_2$, in this one instance, introduces negligible error in the final result, but simplifies Eq. 23 to the following form:

$$ {}_{p}L_x = {}_{p}A_x(1 - {}_{p}N_x) + S_i \qquad [25] $$

Under gas injection it is assumed, as previously pointed out, that the injected gas does not enter the tighter portions of the reservoir, and that the oil recovered from these tighter portions is exactly the same at any given pressure as it would have been under primary recovery. The fraction of the oil-productive reservoir represented by the more permeable portions into which the gas moves is called the conformance factor, *e*. The liquid saturation in the *e* portion of the reservoir, the so-called "flow channels," can be shown to be defined by the following equation:

$$ {}_{gi}L_{xe} = \frac{e \cdot O_2 \cdot \left(\frac{{}_{d}F_x}{{}_{d}F_2}\right) - ({}_{gi.cf}N_x)({}_{h}F_x) + ({}_{pcf}N_x)({}_{h}F_x)(1 - e)}{e \cdot \left(\frac{O_2}{1 - S_i}\right)} + S_i \qquad [26] $$

By the substitution, in the preceding equation, of ${}_{d}F_x$ for ${}_{h}F_x$, which can be shown to introduce negligible error in the final answer, and since $O_2/{}_{d}F_2 = 1$, the following equation can be developed:

$$ {}_{gi}L_{xe} = {}_{gi}A_x[e - ({}_{gi}N_x) + (1 - e)({}_{p}N_x)] + S_i \qquad [27] $$

wherein

$$ {}_{gi}A_x = \frac{{}_{d}F_x}{{}_{d}F_2} \cdot \frac{(1 - S_i)}{e} = \frac{{}_{p}A_x}{e} \qquad [28] $$

The K_g/K_o value, as determined from the liquid saturation obtained by solving Eq. 27 and 28, may be used directly for the evaluation of reservoir performance of the entire reservoir under gas injection, and provided a suitable conformance factor has been selected, this should give a truly representative prediction. Such predictions are based on the assumption that the oil from the $1 - e$ portion of the reservoir, in going to the well bore, flows through the *e* portion of the reservoir, wherein the gas-oil ratio is determined by the prevailing liquid saturation in the *e* portion at any given time. Thus it is assumed that, at any given pressure

$$ {}_{gi}\left(\frac{K_{gx}}{K_{ox}}\right) = {}_{gi}\left(\frac{K_{gx}}{K_{ox}}\right)_e \qquad [29] $$

Correction for Originally Undersaturated Condition

Condition 2 has been defined as the bubble-point condition, and $O_2/{}_{d}F_2$ has been assumed to have a value of 1.00 in order that N_x values will be the stock-tank oil produced from the bubble point expressed as fractions of the stock-tank oil in place at the bubble point. If the reservoir under consideration was originally undersaturated, the N_x values must be corrected for the amount of oil produced from the initial pressure to the bubble point. If N_x' is defined as the stock-tank oil produced from the initial reservoir pressure to the pressure at condition *x*, expressed as a fraction of the stock-tank oil originally in place at the undersaturated condition of initial reservoir pressure (initial oil being converted from reservoir to stock-tank conditions by differential liberation), the N_x values may be corrected by the following equation:

$$ N_x' = N_x[1 - c(P_1 - P_2)] + c(P_1 - P_2)\frac{{}_{d}F_2}{{}_{h}F_2} \qquad [30] $$

Intercommunicating Reservoirs

If a field has two or more reservoirs present, each having different bubble points and reservoir fluid characteristics, and if the individual wells in the field have two or more reservoirs producing through the same string of pipe, it is advisable to make independent material balances on each reservoir and then combine these reservoir performance predictions. If the reservoirs are not too widely separated vertically, the performances may be combined on the basis of the assumption that the same pressure will exist in both reservoirs at the same time although each will have contributed a different percentage of the total oil production from the combined reservoirs. The oil produced from each of the several reservoirs may be combined on a fractional basis at any given pressure by multiplying the N_x' value of each reservoir by the respective fraction that its oil initially in place bore to the total oil initially in place for all the reservoirs being combined, and by then making a summation. The fraction of the total oil each reservoir produced for any pressure interval is then multiplied by its respective average instantaneous gas-oil ratio for that interval to determine the gas production from each reservoir for each pressure interval. For any pressure interval, the incremental gas production from all of the reservoirs is added together and the summation is divided by the increment of oil production for the combined reservoirs to obtain the average instantaneous gas-oil ratio for the combined reservoirs. If the reservoirs are widely separated vertically, some correction should be made for the weight of the fluid column between the two reservoirs in making such a combined performance prediction.

CONVERSION TO TIME

Productivity Index

Muskat and Evinger[13] have shown that, at any given reservoir-pressure condition, the productivity index of a well will vary with the producing pressure differential at the well bore and the gas-oil ratio, which is intimately related therewith. In converting pressure and gas-oil ratio predictions from a function of oil recovery to a function of time, field average productivity indexes may be used, and at any given pressure, only one value for the producing pressure differential is applied. The average producing pressure differential that is applied can be considered to remain constant throughout the productive life of the reservoir (as was pointed out elsewhere), or it can be considered to vary slightly. In either event, however, the effect of variations in average producing pressure differential upon the productivity index can, within the usual limits of accuracy of determining the average productivity index for a field, be neglected. If the effect of these variations, and the consequent variations in gas-oil ratio, is neglected, a simple equation for the relative decline in productivity index evolves as:

$$\frac{PI_x}{PI_1} = \left[\frac{U_{o1} \cdot {}_hF_1}{(K_o/K)_1}\right] \frac{(K_o/K)_x}{U_{ox} \cdot {}_hF_x} \qquad [31]$$

Eq. 31 can be further simplified in use into the two following equations:

$$\frac{PI_x}{PI_1} = a \frac{(K_o/K)_x}{U_{ox} \cdot {}_hF_x} \qquad [32]$$

$$a = \frac{U_{o1} \cdot {}_hF_1}{(K_o/K)_1} \qquad [33]$$

For those who desire further refinement, Babson[1] has presented a method for taking into account the effects of finite variations in producing pressure differential which gives an answer that, theoretically, is closer to what actually takes place in a reservoir.

Babson's equation, using the symbols as defined herein, is as follows:

$$\frac{PI_x}{PI_1} = \frac{U_{o1} \cdot F_1}{(K_o/K)_1} \left(\frac{1}{P_s - P_f}\right) \int_{P_f}^{P_s} \frac{(K_o/K)_x}{U_{ox}F_x}\, dP \qquad [34]$$

Oil Rate

In converting the gas-oil ratio and reservoir pressure predictions to a function of time, use is made of the following simple equations:

$$N_x = N_{x-1} + \Delta t \cdot {}_aD_x \qquad [35]$$

$$D_x = {}_aPI_x \cdot W_x \cdot \Delta P_m \qquad [36]$$

$$D_x = 2\,{}_aD_x - D_{x-1} \qquad [37]$$

WELL-HEAD INJECTION PRESSURES

In order to predetermine well-head injection pressures, the following equations are employed:

$$P_f = 1000 \sqrt{\frac{Q \cdot Z \cdot U_g(460 + T_r) \log_{10} (X_d/X_r)}{E \cdot H \cdot K \cdot (K_g/K)} + \left(\frac{P_s}{10^3}\right)^2} \qquad [38]$$

$$P_w = \left[\frac{(460 + T_g)Z - 0.009379gM}{(460 + T_g)Z + 0.009379gM}\right] P_f \qquad [39]$$

Muskat[14] gives the basic equation for radial flow of gas from which Eq. 38 resulted. Fancher[12] modified Muskat's equation to accommodate units equivalent to those used herein, and presented the equation in a form basically the same as Eq. 38. Using these units, Fancher gives a value of 0.312 for *E*.

PIPE SIZE

Weymouth's formula may be used to determine the sizes of pipe required for the gathering and distribution systems and also for determining the plant-discharge pressures. It will probably be found useful in the following form:

$$Q = \frac{0.2254}{P_b}\, d^{2.67} \left[\frac{P_d^2 - P_w^2}{g \cdot M'(460 + T_g)}\right]^{1/2} \qquad [40]$$

HORSEPOWER

Neglecting supercompressibility, the following equations can be used to compute the brake horsepower required per million cubic feet of gas injected:

$$C_r = \left[\frac{P_d}{P_n}\right]^{\frac{1}{s}} \qquad [41]$$

$$n = \frac{C_p}{C_v} \qquad [42]$$

$$k = 6.41 \frac{n}{n - 1} \left[(C_r)^{\frac{n-1}{n}} - 1\right] \qquad [43]$$

$$\frac{H_p}{Q} = 6.944 \left[\frac{460 + T_a}{520}\right] \frac{P_b}{14.7} \cdot \frac{sk}{E_m} \qquad [44]$$

Prediction of Reservoir Performance

CALCULATION OF PAST PRESSURE

This step is often deleted, particularly, as pointed out elsewhere, if the percentage of depletion the reservoir has undergone is especially small. If a sufficient quantity of reliable reservoir and pressure data is available to make the calculations, the results are usually worth while for the purpose of supporting other behavior predictions.

In order to calculate the past pressure performance, knowing the original pressure and the bubble-point pressure, one may assume a certain pressure value, evaluate the constants C_x and I_x in Eqs. 10 and 11, and then make trial substitutions of cumulative net produced gas-oil ratio and the corresponding value of the produced oil (fractional basis) in Eq. 12 until that equation is satisfied. If this is done at several successive pressures until the last calculated value of N_x equals the actual cumulative produced oil as far as the statistics go, the result will represent the idealized average equilibrium pressure-behavior history.

PREDICTION OF PRESSURE AND GAS-OIL RATIO AS FUNCTIONS OF RECOVERY

Primary

Several pressure values depicting the complete future pressure history may be assumed at once, or instead it may be preferable to choose only one value at a time, and the magnitude of each successive pressure interval can then be chosen according to the corresponding position of the previous value on the gas-oil ratio curve. In any event, the constants ${}_pA_x$, B_x, C_x, and I_x should be evaluated for each assumed pressure by substitution in Eqs. 24, 17, 10 and 11, respectively. The value of ${}_hS_x$ should be tabulated also for each pressure. For the first pressure point, a value of ${}_pN_x$ is assumed and ${}_pL_x$ is calculated by use of Eq. 23. The corresponding value of ${}_p(K_{gx}/K_{ox})$ is then read from the previously drawn curve. The value of r_x is then calculated from Eq. 16, and r_x' is calculated therefrom. Eqs. 21 and 22 are then used to calculate G_x, and R_x is obtained by dividing G_x by N_x. Eq. 12 may then be evaluated. If the left-hand side of the equation is less than 1.000, a larger value for ${}_pN_x$ should be assumed, or vice versa, and another trial balance made. These steps are repeated until Eq. 12 is satisfied, and the correct ${}_pN_x$ value is thereby indicated. The same procedure is used on each of the remaining pressure values in succession. N_x' is then obtained from N_x by use of Eq. 30 and converted from percentage to barrels.

The N_x' and r_x values thus obtained are each plotted against the corresponding pressure values, and a smooth curve drawn both for N_x' vs. pressure and for r_x vs. pressure.

Pressure Maintenance without Plant Limit

Usually it will be found advantageous to select the same pressure points for depicting performance under gas injection as were selected for primary recovery. Therefore ${}_hS_x$, B_x, C_x, and I_x will be the same for primary recovery as for gas injection at corresponding pressure values. However, ${}_{gi}A_x$ values will not be the same as ${}_pA_x$ values, and should therefore be evaluated by Eq. 28, or simply by dividing ${}_pA_x$ by e. For the first pressure point, a value of ${}_{gi}N_x$ is assumed and ${}_{gi}L_{xe}$ is solved for in Eq. 27. The ${}_{gi}(K_{gx}/K_{ox})_e$ value corresponding to ${}_{gi}L_{xe}$ is then read from the curve. The value of r_x is then calculated from Eq. 16 and r_x' from Eq. 20.

If extraction facilities are to be employed in connection with the operation, the value of i in Eq. 22 will depend upon the composition of the produced gas and upon what components are to be extracted. If gasoline extraction is contemplated, but not actually in operation, an estimate of extraction losses may be made from average hydrocarbon analyses of the produced gases. In addition, gasoline-plant fuel, compressor and dehydrator-plant fuel, lease fuel, and so forth, should be considered in estimating the percentage of produced gas to be available for injection purposes.

R_x is then obtained by dividing G_x by N_x after evaluating G_x from Eqs. 21 and 22. Eq. 12 should then be evaluated, and the procedure repeated at new assumed values of ${}_{gi}N_x$ until the equation is satisfied. After the correct value for ${}_{gi}N_x$ is obtained at each pressure point, N_x' is then obtained from N_x with Eq. 30. The N_x' values should then be converted from percentage of oil in place to cumulative barrels recovered, and N_x' and r_x should be plotted against pressure as was done for primary recovery. Several intermediate steps are necessary in order to convert the performance curves to time.

PREDICTION OF AVERAGE DECLINE OF PRODUCTIVITY INDEX

Separate predictions for decline of productivity index must be made for primary recovery and for pressure maintenance. The relative *PI* decline may be computed first on a fractional basis from initial reservoir pressure to depletion by means of Eqs. 32 and 33 and data previously assembled, or by means of Eq. 34. If several reservoirs having different fluid-behavior characteristics are intercommunicating, the problem is not quite as simple. For either primary recovery or pressure maintenance, the relative productivity-index decline is calculated for each reservoir, and the combined relative productivity-index decline is then calculated therefrom. This combination may be approximated, if the reservoirs are not too widely separated vertically, by assuming that the average producing pressure differential of each reservoir is the same as that of each of the other intercommunicating reservoirs at all times.

If some of the productivity-index data do not represent initial conditions, they should be converted to the basis of initial conditions by means of relative decline computations. Where there is a several-fold variation in range in the previously accumulated initial productivity-index data, it is advisable to arrange the data into several groups in some fashion having an orderly variation of group averages. Each group of productivity-index data should represent approximately the same percentage of the total number of wells and should have a definite range in values not overlapping the range of any other group. The statistical average productivity-index value for each group should be ascertained. The results of relative productivity-index decline corresponding to subsequent reservoir-pressure values should then be applied to each group average, thus yielding an absolute *PI* value at each reservoir pressure for each group. Whenever the average absolute *PI* value of any group falls below the minimum required to produce a well at commercial withdrawal rates, this and subsequent values of that group should be deleted, as it can be assumed that these wells will be abandoned as soon as they reach their economic limit. With these deletions, the average absolute *PI* for the field is computed at each chosen pressure point. If too few groups of *PI* values are chosen, the average absolute *PI* values probably will not give a smooth curve when plotted against pressure. Such irregularities as may exist should be smoothed graphically. From this curve, a curve of *PI* vs. cumulative oil recovery should be plotted. This method assumes that the individual *PI* values used in obtaining the averages represent the maximum values obtainable for the corresponding wells irrespective of completion practice. If such an assumption is not true—for example, if certain wells were not open to the full section in which they could have been practicably completed—adjustments should be made to account for possible future increases in productive ability as a consequence of workovers.

Economic Limit

The economic limit referred to in the preceding paragraph may be computed by dividing the estimated operating expense per well per year by the product of 365 times the working interest, times the difference between the estimated price to be received per barrel and the estimated severance, and/or ad valorem, and/or regulatory taxes per working interest barrel. The operating cost per well per year will be based on pumping-well costs for primary recovery. For pressure maintenance, it might, under the proper circumstances, be possible to flow most wells to abandonment. The question as to whether to use operating costs of flowing or of pumping wells, or some intermediate value, for determination of the economic limit under pressure maintenance, will depend upon the gas-oil ratio at depletion, certain physical characteristics of the reservoir, and possibly other factors.

Inasmuch as the oil-recovery increase due to gas injection is dependent upon economic limit, which in turn is a function of operating expense per well per year, and inasmuch as the additional benefits of gas injection resulting from deferred pumping are dependent upon operating cost per well per year, it can readily be seen that the operating-cost figure plays an extremely important role in the evaluation of pressure maintenance. The *lower the operating cost* per well per year by pumping methods, the lower will be the economic limit (assuming the same number of barrels per well per day for the economic limit under both primary and pressure maintenance), thus resulting in a *greater recovery increase* for pressure maintenance over primary. However, for any specific value of operating cost per well per year by flowing methods, a *decreased value of the unit cost of pumping* a well will result in a *smaller increase in savings* by gas injection *due to deferred pumping*. Therefore, the unit operating cost figures should be evaluated with extreme care.

Ultimate Recovery

The average *PI* at the economic limit, and the reservoir pressure corresponding thereto, may be determined by dividing the economic limit (barrels per day per well) by the *MEPPD* (pounds per square inch), or, if the reservoir pressure declines below the *MEPPD* before this value of *PI* thus obtained is reached, the economic limit should be divided by successively smaller values of the reservoir pressure until this quotient is identical with the *PI* at the corresponding reservoir pressure. The ultimate recovery may then be obtained from either of the previously plotted curves of *PI* vs. Cumulative Oil Recovery or Reservoir Pressure vs. Cumulative Oil Recovery.

Prediction of Number of Producing and Injection Wells

If field development is incomplete, the previously assembled development-rate data should be extrapolated graphically to the estimated future total number of wells, which number is based on the spacing rules or practice, and the size of the major development area. Ordinarily, in a project of this type, few if any wells will have been abandoned at the time of the study. Without any abandonment history to which to tie the abandonment-rate prediction, the prediction usually is made on the basis of the absolute *PI* decline prediction. The percentage of the total number of wells thus assumed not to have been abandoned at any pressure, from the *PI* decline relations, is converted to the actual number of producing wells in the field, by multiplying by the maximum number of wells at full development for primary. For pressure maintenance, an additional factor of one minus the ratio of injection wells to total wells must enter the product. This procedure assumes that injection wells will be abandoned along with their respective allocation of producing wells. An alternative sometimes used is to assume that the number of injection wells will remain constant. The number of producing wells may then be plotted against pressure. Any sharp breaks in this curve may be smoothed graphically. The number of wells prediction then may be put into more useful forms by plotting against cumulative oil recovery and against time.

Conversion of Recovery, Pressure, and Gas-oil Ratio Predictions to a Function of Time

Primary

Recovery is first converted to a function of time, and then, since pressure and gas-oil ratio were calculated originally as a function of recovery, they can be converted readily to a time basis. As previously mentioned, in prorated fields it is necessary to make an assumption as to the allowable production for the next few years. If the evaluation is to be converted to a present-worth basis, probably it will be found preferable to compute the oil rate by one or two-year periods. The time at which the field will no longer produce its assumed allowable may be calculated by trial and error solutions of Eqs. 35, 36 and 37. For the first trial the allowable is substituted in Eq. 35, which is solved for the cumulative oil recovery to the end of that period. This cumulative is averaged with the previous cumulative to the beginning of the period, and the average *PI* for the period is obtained from the previously plotted curve of *PI* vs. Cumulative Oil Recovery. W_x is then read from the respective curve and

Eq. 36 is solved for D_x. If this value of D_x is higher than the allowable assumed, the field is still capable of producing its allowable, and so the next trial should be made for a subsequent period. When the value of D_x obtained from Eq. 36 no longer is equal to or greater than the allowable, a lower value for ${}_aD_x$ is assumed, Eq. 35 is solved for N_x, and Eqs. 36 and 37 are solved for D_x. Different values of ${}_aD_x$ should be assumed until the solutions of Eqs. 36 and 37 result in identical values for D_x for each period.

Pressure Maintenance

Without Plant Limit.—The steps are the same for pressure maintenance without plant limit as those for converting primary recovery predictions to a function of time, except that the appropriate sets of curves applicable to pressure maintenance must be used.

At Various Plant Sizes.—If it is assumed that no excess gas is sold or popped to the air, and if the assumed plant size is such that the field is capable of producing more gas than the plant can handle, the oil rate must be retarded when the gas rate would otherwise exceed the plant capacity. Therefore, while making the conversion to time, it is necessary to keep a running tabulation of gas-oil ratio, daily oil rate and daily gas rate. Whenever the daily rate of production of gas available for injection reaches the compressor-plant capacity, the oil rate is then calculated by dividing the compressor-plant capacity by the average gas-oil ratio, and in turn by the fraction of produced gas available for injection. A running tabulation should be kept of the potential oil rate calculated by Eq. 36, as well as the actual oil rate as limited by plant capacity, in order to determine the time at which the *PI* restricts the oil rate to the extent that the gas production rate again falls below the capacity of the plant. Other than the preceding limitations, the conversion to time for any given plant size under pressure maintenance is made in the same way as for no plant limit.

Sometimes, for the purpose of economic comparison, an evaluation may be made on the basis of the assumption that, instead of retarding the oil rate, the excess gas above the plant capacity is vented or sold. Whenever the plant capacity is exceeded in such a computation, it is necessary to go back to the original trial balance and, making the appropriate correction for the value of i in Eq. 22, the trial balances for prediction of pressure and gas-oil ratio behavior must be made with the new i values, at the same time the conversion to time is made by the previously described method.

Alternate Methods

Sometimes a short study must be made of a field from which there are no *PI* data available. In such instances decline-curve methods may be applicable for converting performance data to time.

PREDICTION OF PERCENTAGE OF TOTAL WELLS THAT ARE PUMPING

Although some pressure-maintenance projects may be justified on the basis of increased oil recovery alone, the savings by pressure maintenance over primary recovery as a consequence of either the elimination or the deferment of the pumping stage is quite important. However, the prediction of the number of pumping wells is unquestionably the least accurate prediction involved in such an evaluation at the present stage of our knowledge. The percentage of total wells pumping may be predicted first as a function of pressure, and then converted to time, although occasionally more arbitrary methods are employed by directly estimating the percentage of pumping wells as a function of time. While no very reliable method for making this prediction has yet been published, the curve of Kemler and Poole,[15] Fig. 8, can be utilized in the following manner:

This curve should be replotted so that the ordinate will read "pressure drop in the tubing, lb." for the average depth of the reservoir under consideration, instead of "pressure drop, lb. per sq. in. per ft." The predicted flowing bottom-hole pressure is obtained from each of the calculated static-pressure points in the required range, and plotted on the same curve with the Kemler and Poole data against the corresponding predicted gas-oil ratio values for both primary recovery and pressure maintenance, as in Fig. 9. When a suitable value for the flowing tubing pressure, with perhaps an added safety factor, has been added to the pressure value corresponding to the intersection of each of these curves with the Kemler and Poole curve, an approximation of the bottom-hole pressure at which the average well will cease flowing by natural means should result. The estimated producing pressure-differential must then be added to this value to convert to the average equilibrium reservoir pressure corresponding to the time at which the average well will cease to flow naturally. If initially *no* wells are pumping, then since at field abandonment, or before, *all* wells will be pumping, this average value should correspond to the point at which approximately half the number of the wells will be pumping. If some wells are pumping at the time the study is being made, this history will tie in one end of the curve. It should be remembered that the material-balance prediction of reservoir pressure gives merely the true *equilibrium* reservoir pressure. In tight reservoirs there is considerable variation throughout the field above and below the average measured pressure, and this average measured pressure will be lower than the true equilibrium pressure. Wells will cease to flow sooner as a result of the additional decline in the actual pressures measured at the well bores, before the true equilibrium pressure has declined to the minimum value required to maintain flow. The *average* reservoir pressure corresponding to the time at which the last well is put on the pump could be reasonably assumed to be at least as much lower than the pressure at which 50 per cent of the wells are pumping, as the amount which the highest pressure in the field at the time of the most

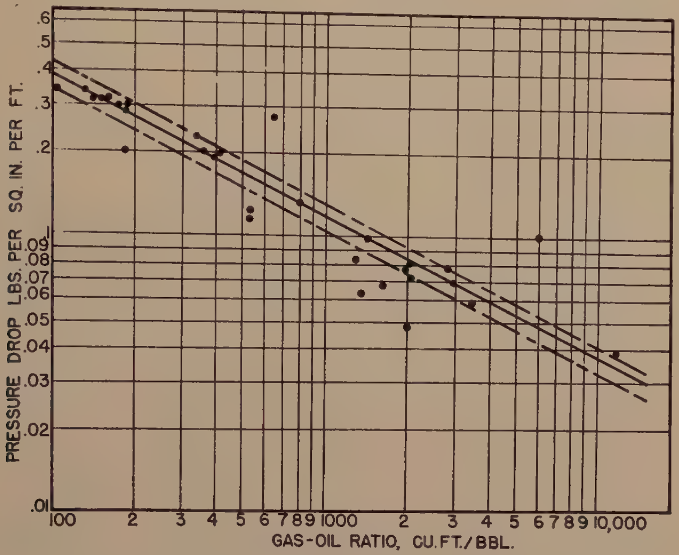

FIG. 8.—CURVE FOR BASIS FOR PREDICTION OF PERCENTAGE OF WELLS THAT ARE PUMPING.
Reproduced by permission from paper by Kemler and Poole.[15]

recent pressure survey exceeds the average reservoir pressure at that time. This assumption is based on the hypothesis that at the time when the last well in the field becomes a pumping well, the same difference will exist between the average reservoir pressure and the maximum reservoir pressure as exists at the time of the study. With the pressure values thus obtained for 0, 50, and 100 per cent of the wells pumping, and with any pumping history on the field that may be available, a curve of percentage of total wells on the pump may be constructed as a function of pressure, and thence converted to a function of time. This assumption may not necessarily hold true for either primary or pressure maintenance. However, while such curves will not accurately predict this phase of performance under any one method of operation, the relationship between the primary and pressure-maintenance curves thus constructed should serve as an approximate means of computing the relationship between the direct operating costs under primary as compared to pressure maintenance.

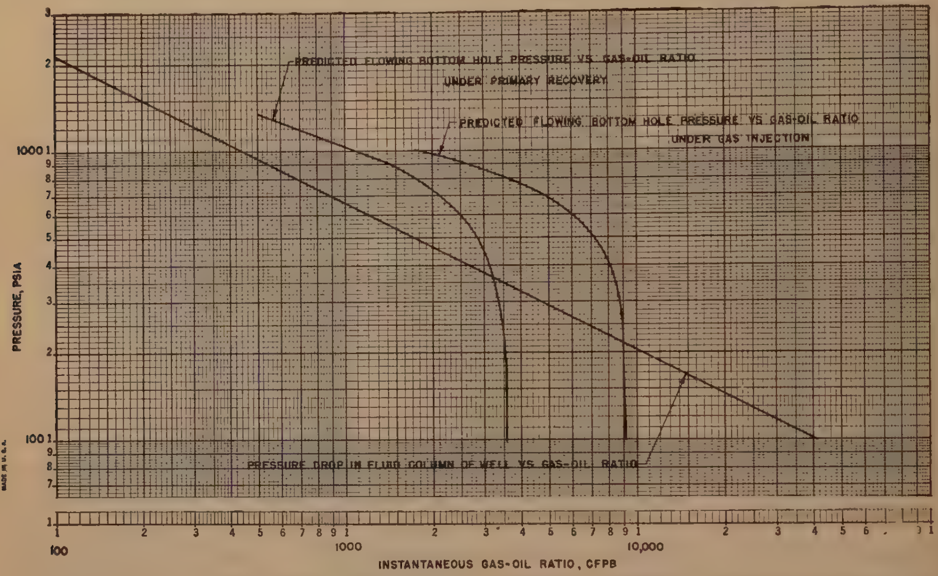

FIG. 9.—METHOD OF ESTIMATING DIFFERENCE IN RESERVOIR PRESSURE AT END OF FLOWING LIFE BETWEEN PRIMARY RECOVERY AND GAS INJECTION.

Prediction of Requirements of Pressure-maintenance System

WELL-HEAD INJECTION PRESSURES

Equation 38 may be used to calculate the average equalized sand-face pressure necessary to inject the required volumes of gas into each injection well. The average volume to be injected per well at any time is found by dividing the product of the gas produced by the field and the fraction of the produced gas returned to the reservoir by the number of injection wells.

The well-head injection pressure is calculated from the injection pressure at the sand face by Eq. 39, which has been simplified by neglecting the frictional pressure drop in the pipe. The well-head injection pressure should be computed for each of the successive reservoir-pressure points.

Before the plant is actually designed and installed, if such installation is found to be feasible from both an economic and an engineering standpoint, it will usually be found desirable to supplement these calculations with data from actual pilot injection tests. The calculations without the benefit of the tests for confirming net effective thicknesses and other contingent factors, however, should be sufficiently reliable for use in connection with the determination of the economic feasibility of the project.

GATHERING AND DISTRIBUTION SYSTEM

In determining the most desirable pipe size or combination of pipe sizes in the design of the gathering and distribution system, several alternatives may be selected and the corresponding future pressure drops computed by Weymouth's formula, Eq. 40. The calculations must be made throughout the entire future range of pressures and gas volumes, because, for example, the distribution system must take care not only of the low initial volumes at high initial pressures but also of the increased volumes at low pressures incident to the future rise in gas-oil ratios, without excessive pressure drops. The correct choice of size of pipe should then rest on an economic balance between decreased compression ratio and horsepower requirements due to lower pressure drops with larger pipe sizes, and increased cost of gathering and distribution lines as a result of the larger pipes. The selection often is made on the basis of past experience and judgment.

HORSEPOWER REQUIREMENTS

Suction Pressure

The suction pressure will depend upon the field-separator pressure and/or upon whether or not a gasoline-extraction plant is to be operated in the field.

Plant Discharge Pressures and Compression Ratios

When the distribution system has been designed the future plant discharge pressures can be calculated from the well-head injection pressures by Eq. 40. The future compression ratios should then be computed from Eq. 41.

Installed Brake-horsepower Requirements

Equation 42 is used to compute the ratio of specific heats. The majority of wet gases have an n value lying probably within the range from 1.15 to 1.28. If the fractional gas analysis is not available from which to calculate the specific heat values, a value of 1.24 would probably serve as a fair approximation for n. The value of n will vary slightly with changes in pressure but these variations are usually neglected. The installed brake horsepower required per million cubic feet of gas compressed per day may then be obtained for each point throughout the life of the project from Eq. 44. These values when multiplied by the corresponding values of the gas to be injected (expressed in millions of cubic feet) will result in the prediction of the number of horsepower to be operated throughout the project.

The k values are sometimes read directly from a set of curves correlating k as a function of compression ratio for different values of n. Some compressor manufacturers can supply sets of curves correlating H_p/Q directly as a function of over-all compression ratio for different values of n. The latter naturally must be based on a fixed operating temperature and base pressure. Values obtained from this type of curve should be corrected for whatever divergence there may be between actual conditions and the assumptions upon which the curves were based. Since usually it will not be necessary to install the maximum compressor capacity the first year, a schedule should be made showing when additional installations will be needed.

DEHYDRATOR AND DESULPHURIZER

A dehydrator unit ordinarily will be required by the compressor plant, no part of which usually can be charged justifiably to the gasoline-extraction plant.

If sour gas is produced, a plant for removal of hydrogen sulphide may be found necessary in order to prevent corrosion of pipe and clogging of injection wells. If so, the investment and operating cost usually can be split equitably between the compressor plant and the extraction plant, on the assumption that the gasoline plant will also derive benefit from the extraction of the acid gases through minimizing corrosion of extraction equipment. These costs are sometimes split on a 50-50 basis, and sometimes in the same proportion as the number of stages of compression chargeable to each plant. By operating the gathering system under a positive pressure, if the gas is not too sour, it may be possible to eliminate the installation of any desulphurization unit in fields wherein the nature of the produced gas would otherwise make removal of hydrogen sulphide necessary. Such practice would require higher separator pressures, which would tend to result in higher gravity and consequently higher prices for the stock-tank crude, but would be offset by the disadvantage of lower gas volumes and leaner wet-gas mixtures to the gasoline plant.

Pilot Injection Tests

As pointed out elsewhere, usually it will be found desirable to make experimental field injection tests before building a large compressor plant. Such tests, correctly interpreted, should permit an intelligent decision as to the susceptibility of the reservoir to this type of project. It may be found that certain reservoirs, having all other physical characteristics indicating the engineering feasibility of internal gas injection, may possess one or more less obvious physical qualities that would make this type of project unprofitable. Such tests may be made concurrently with the reservoir-behavior predictions and economic evaluation. The introduction of some detectable gas (such as helium) into the input wells, and the analysis of the gas produced from the surrounding wells, will be conducive to a more positive determination of the possibility of channeling. These tests, in addition, will permit well-head injection pressures to be more accurately determined than is possible by calculation alone not supplemented by field tests.

Economic Evaluation

Separate economic evaluations are required for the field as a whole for both primary recovery and for pressure maintenance. These separate evaluations can be made for each system in the form of profit or loss estimates. Such statements preferably are broken down by one-year periods for at least 10 or 20 years, and thence by longer periods.

The benefits resulting from consolidation of personnel and equipment incident to unitization may or may not be considered. Such benefits will not be discussed here in detail.

Although gasoline-plant revenue and expenditures usually are considered part of a separate evaluation, a portion of the gasoline-plant revenue must be credited, after deduction of royalty interest, to the lease operator as working interest. However, for the purpose of the present discussion, revenue from plant products will not be considered under either primary recovery or pressure maintenance.

Revenue

Gross

Equilibrium constants may be utilized in connection with the hydrocarbon analysis of the produced oil and gas to predict the future average gravity of stock-tank oil for any fixed separator pressure as a function of reservoir pressure. This is a refinement occasionally used for fields where the price of oil is set on a gravity basis. However, in order to make this computation for pressure maintenance by internal gas injection, it is necessary to assume full or partial phase equilibrium within the reservoir between the injected gas and the oil and gas already in the reservoir. Any such assumption at the present time must be of an arbitrary nature. For most purposes it is well enough to assume the gravity of the oil to remain constant throughout the life of the reservoir. The price of oil usually is assumed to remain constant. Any reasonably assumed price fluctuation should be applied equally to both primary recovery and pressure maintenance.

Operator's Interest

The operator's interest is computed from the gross revenue by deducting the royalty interest.

EXPENDITURES

Expense

Taxes.—The taxes referred to here do not include federal income tax. Ad valorem taxes on the compressor plant are included. In Texas these may be estimated at 2.75 per cent per year on 25 per cent of the investment. The subject item also includes severance, state regulatory and the usual ad valorem taxes on the producing property. The sum of the three is usually computed by applying a unit figure to the number of working interest barrels produced during each period. Taxes vary from one locality to the next. In Texas present statutes call for a severance tax of 4⅛¢ per barrel on every barrel selling for $1.00 or less, and 4⅛ per cent of the selling price on every barrel selling for over $1.00. In addition, a state regulatory tax of 3⁄16 of 1¢ per barrel is levied. Ad valorem taxes are levied locally by counties, school districts, etc., and are based on the evaluation of the property including underground reserves. On a barrel basis these taxes vary widely. Many oil companies have total tax per barrel figures available for various fields.

Well-operating Costs.—Total yearly well-operating costs may be computed from a unit basis of so many dollars per well per year. The unit cost of operating a pumping well will be higher, of course, than that of a flowing well. Although both will vary with depth, the average operating cost of a pumping well usually will increase more rapidly with depth than that of a flowing well. Both will vary with future economic conditions but in all likelihood there will always be some differential between the two. A reasonably sound estimate of the savings in well-operating costs by pressure maintenance due to deferred pumping may be made by applying the yearly per-well unit operating cost estimates to the predictions of the number of pumping and flowing wells herein discussed. These costs should include workovers and replacements, and ordinarily will include all field office or district overhead. Detailed cost analyses can be made to arrive at fairly accurate current unit cost figures if they are not already available. Cost of operating injection wells ordinarily will be included under this heading.

Plant and Lines.—Detailed operating-cost breakdowns should be made to include maintenance, repairs, materials, and labor for operating compressor plant, desulphurizer (if any), dehydrator, injection lines, supervision, and other items. The distribution of the cost of operating the gathering system will depend upon whether or not the gas will be processed by an extraction plant. This cost analysis should be converted to a unit figure of so many dollars per year per horsepower operated. The total cost of operating plant and lines for each future period can then be computed from the prediction of horsepower requirements. If extraction facilities are planned or in operation, the cost of reinjecting the residue gases into the formation may be somewhat lessened because of the possibility of charging one or more stages of compression to the gasoline plant.

Investment

Well.—Tangible and intangible future development costs in a partially developed field may be omitted from the economic analysis on the premise that they will be the same for pressure maintenance as for primary recovery and therefore will not affect the difference between the two systems in net revenue before federal income tax. The cost of individual pumping units of the required size installed complete with engine, clutch, sucker rods, housing, and other necessary parts should be estimated, and the total cost of the required number of new units for each period computed. A certain percentage of the pumping units installed in most instances may be assumed to be transferred from abandoned wells, in which case the full price of the new units should not be charged against the operation.

Plant and Lines.—The plant investment should include compressors, dehydrator, and hydrogen sulphide removal unit (if necessary). Compressor-plant and dehydration-plant investment can each be figured conveniently on a unit cost basis of so many dollars per horsepower. Injection-line investment can be estimated from a unit cost per foot or per mile including installation. This unit cost will vary with the size and weight of pipe used. Meter runs, valves, fittings, and other small parts are not included usually in these unit costs and must be computed separately and included hereunder.

Interest on borrowed capital sometimes can be eliminated by completely amortizing each year's investment out of current revenue. However, if the ratio of investment to current revenue is nearly unity or greater, it may be necessary to include interest on borrowed capital as an item under investment, amortizing the investment over perhaps a 5 or 10-year period.

Federal Income Tax

Federal income tax nearly always is omitted in joint studies made by committees through the cooperation of several producing organizations. One reason is because various producers may be in different income tax brackets. Another reason is that most producers would not be taxed in direct proportion to the profit from any one field. Individual producers in computing their share of the increased profit for the field may wish to include the federal income tax item.

EXCESS OF REVENUE OVER EXPENDITURES

The excess of revenue over expenditures for each period should be computed for both primary recovery and pressure maintenance. The cumulative excess of revenue over expenditures should then be computed for each system.

ECONOMIC COMPARISON

The difference between this cumulative figure for primary recovery and for pressure maintenance should be computed for each period. This difference will reflect the estimated payout status of the proposed pressure-maintenance program. The difference ordinarily will be a deficit for the first few years. This does not mean that the field actually will be operating at a deficit, however, except from a comparative standpoint. The number of years expiring before the comparative cumulative deficit becomes a comparative cumulative surplus, or, in other words, the number of years required for the pressure-maintenance system to pay out, considered together with the cumulative surplus at abandonment, should determine the feasibility of the project.

Another method of making the comparison would be to compute the difference between the two systems in the present worth of the excess revenue over expenditures based on a suitable discount rate.

There are other methods of handling the details of the economic phase of the evaluation. It is believed that the method presented will give a clear picture of the economic comparison of the two different

Nomenclature

Symbol	Definition
a	Constant defined by Eq. 33
${}_{p}A_{x}$	Constant for any pressure, defined by Eq. 24
${}_{gi}A_{x}$	Constant for any pressure, defined by Eq. 28
B	Constant for any pressure, defined by Eq. 17
c	Compressibility of saturated reservoir oil, cu. ft. per lb. per cu. ft. of bubble-point liquid
C	Constant for any pressure, defined by Eq. 10
C_r	Compression ratio for each stage of compression
C_p	Specific heat of gas at constant pressure, same units as C_v, usually B.t.u. per lb. per deg. F.
C_v	Specific heat of gas at constant volume, same units as C_p, usually B.t.u. per lb. per deg. F.
d	Inside diameter of pipe, in.
D_x	Instantaneous field average daily oil rate at condition x, bbl. per calendar day
${}_{a}D_{x}$	Field average daily oil rate for interval $(x - 1)$ to x, bbl. per calendar day, $= \frac{D_{x-1} + D_x}{2}$
e	Conformance factor, or the ratio of the net effective pore space, the saturation distribution of which has been affected at any pressure by the movement or presence of injected gas therein, to the total net effective pore space of the entire productive reservoir. See section entitled *Conformance Factor*, fraction
E	Constant defined by Eq. 38
E_m	Mechanical efficiency, fraction
f	Volume of gas measured at base pressure and 60°F. per unit volume of gas in reservoir measured at indicated pressure and reservoir temperature, cu. ft. per cu. ft.
${}_{h}F$	Volume of gas-saturated oil measured in reservoir at indicated pressure and reservoir temperature required to produce unit volume of stock-tank oil (measured at atmospheric pressure and 60°F.) by flash liberation through separator operating at average separator pressure and temperature conditions in field, cu. ft. per cu. ft.
${}_{d}F$	Volume of gas-saturated oil measured in reservoir at indicated pressure and reservoir temperature required to produce unit volume of stock-tank oil (measured at atmospheric pressure and 60°F.) by differential liberation at reservoir temperature to atmospheric pressure, cu. ft. per cu. ft.
g	Specific gravity of gas (air = 1), fraction
G	Cumulative volume of separator gas measured at base pressure and 60°F. produced in association with production of N volumes of oil, cu. ft.
${}_{ef}G$	Cumulative volume of separator gas produced, measured at base pressure and 60°F., cu. ft.
ΔG_x	Volume of separator gas produced in association with $(N_x - N_{x-1})$ volumes of oil during pressure period immediately preceding condition x. May be defined by $(G_x - G_{x-1})$, cu. ft.
H	Net permeable oil-productive pay thickness, ft.
H_p	Installed brake horsepower required
H_p/Q	Installed brake horsepower required per million cubic feet gas (measured at 60°F. and base pressure) compressed per day
i	Ratio of volume of gas returned to reservoir (cubic feet at standard conditions) to gross volume of gas produced from the reservoir (cubic feet at standard conditions), fraction
I	Constant for any pressure, defined by Eq. 11
k	Horsepower factor, theoretical horsepower required for each stage of compression (machine operating perfectly at 60°F.) per 100 cu. ft. gas (measured at 60°F. and 14.7 lb. per sq. in. ab.) compressed per minute
K	Absolute permeability of reservoir rock to homogeneous fluid, md.
K_g	Effective permeability of reservoir to gas phase when three phases are present, md.
K_o	Effective permeability of reservoir to oil phase when three phases are present, md.
K_g/K	Relative permeability to gas, or ratio of effective permeability to gas phase when three phases are present, to absolute permeability of rock to homogeneous, single-phase fluid, fraction
K_o/K	Relative permeability to oil, or ratio of effective permeability to oil phase when three phases are present, to absolute permeability of rock to homogeneous, single-phase fluid, fraction
${}_{p}(K_g/K_o)$	Average ratio of relative permeability to gas to relative permeability to oil for entire reservoir at any specified conditions and phase distribution under primary recovery, fraction

Nomenclature.—(*Continued*)

Symbol	Definition
$_{gi}(K_g/K_o)$	Average ratio of relative permeability to gas to relative permeability to oil for entire reservoir at any specified conditions and phase distribution under gas injection, fraction
$_{gi}(K_g/K_o)_e$	Average ratio of relative permeability to gas to relative permeability to oil for e portion of reservoir at any specified conditions and phase distribution under gas injection, fraction
$_{p}L$	Average liquid saturation of reservoir rock at any specified conditions under primary recovery operations, or ratio of net effective volume of pore space occupied by oil plus water to total volume of net effective pore space, fraction
$_{gi}L_e$	Average liquid saturation in "flow channels" of reservoir rock as defined by e portion at any specified condition under gas-injection operations, or ratio in e portion of reservoir of net effective volume of pore space occupied by oil plus water to total volume of net effective pore space, fraction
m	Number of pound-mols of gas present
M	Length of column (Eq. 39), ft.
M'	Length of flow line (Eq. 40), miles
n	Ratio of specific heat of gas at constant pressure to specific heat at constant volume = C_p/C_v, B.t.u. per lb. per deg. F. per B.t.u. per lb. per deg. F.
N	Cumulative volume of stock-tank oil produced from bubble point (measured at atmospheric pressure and 60°F.) per unit volume of stock-tank oil in reservoir at bubble point, as converted to atmospheric pressure and 60°F. by differential liberation, cu. ft. per cu. ft.
$_{ef}N$	Cumulative volume of stock-tank oil produced from bubble point, measured at atmospheric pressure and 60°F., cu. ft.
$_{p}N$	Same as N, but applying to specified conditions for primary recovery only, as distinguished from gas injection, cu. ft. per cu. ft.
$_{gi}N$	Same as N, but applying to specified conditions for gas injection only, as distinguished from primary recovery, cu. ft. per cu. ft.
N'	Cumulative volume of stock-tank oil produced from initial conditions (measured at atmospheric pressure and 60°F.) per unit volume of stock-tank oil originally in reservoir at initially undersaturated condition (as converted to stock-tank conditions by differential liberation and measured at atmospheric pressure and 60°F.), cu. ft. per cu. ft.
O	Total volume of gas-saturated oil in reservoir at indicated reservoir pressure, measured at indicated reservoir pressure and temperature, cu. ft.
P	Pressure, lb. per sq. in. abs.
P_1	Average equilibrium reservoir pressure at initial conditions, lb. per sq. in. abs.
P_2	Average bubble-point pressure, lb. per sq. in. abs.
P_b	Pressure base, lb. per sq. in. abs.
P_f	Equalized flowing pressure measured at well bore with well producing or with gas being injected, depending upon equation in which it appears, lb. per sq. in. abs.
P_d	Compressor-plant discharge pressure, lb. per sq. in. abs.
P_n	Compressor-plant intake pressure, lb. per sq. in. abs.
P_s	Static equilibrium reservoir pressure, lb. per sq. in. abs.
P_w	Well-head injection pressure, lb. per sq. in. abs.
ΔP_m	Average maximum efficient producing pressure differential (*MEPPD*) between static and flowing reservoir pressure, lb. per sq. in.
PI	Instantaneous average per well productivity index at specified conditions, bbl. per day per lb per sq. in. drop in bottom-hole pressure between static and flowing equilibrium conditions
$_{a}PI_x$	Average well productivity index during interval $(x - 1)$ to x, bbl. per day per lb. per sq. in. drop in bottom-hole pressure between static and flowing equilibrium conditions
Q	Rate of gas injection, millions cu. ft. measured at base pressure and 60°F. per day (per injection well basis in Eq. 38).
r	Instantaneous gross produced gas-oil ratio, cu. ft. per cu. ft.
r'	Average instantaneous gross produced gas-oil ratio for period immediately preceding condition x, cu. ft. per cu. ft.
R	Cumulative net produced gas-oil ratio = G/N, cu. ft. per cu. ft.
R''	Constant for all gases, with a value of 10.72 using units given herein
s	Number of stages of compression
$_{h}S$	Volume of gas released from solution from indicated pressure and reservoir temperature by flash liberation to average separator pressure and temperature conditions existent in field (measured at base pressure and 60°F.) per cubic foot of stock-tank oil (measured at atmospheric pressure and 60°F.), cu. ft. per cu. ft.

Nomenclature.—(*Continued*)

Symbol	Definition
${}_dS$	Volume of gas released from solution from indicated pressure and reservoir temperature by differential liberation at reservoir temperature, to atmospheric pressure and 60°F. (measured at base pressure and 60°F.) per cubic foot stock-tank oil (measured at atmospheric pressure and 60F.), cu. ft. per cu. ft.
S_i	Interstitial (often called "connate") water saturation, fraction of pore space
T_a	Average temperature of gas in compressor, deg F.
T_g	Average temperature of gas in column or line, deg. F.
T_x	Temperature, deg. F., any condition x
T	Temperature, deg. F., absolute (Rankine)
T_b	Temperature base, deg. F.
T_r	Reservoir temperature, deg. F.
Δt	Time interval between condition $(x - 1)$ and x, days
U_o	Oil viscosity, centipoises, at reservoir temperature and specified pressure
U_g	Gas viscosity, centipoises, at reservoir temperature and specified pressure
V	Volume, cu. ft.
V_b	Volume at base conditions of temperature and pressure, cu. ft.
W_x	Average number of wells producing during interval $(x - 1)$ to x
W_{ex}	Net volume of encroached water in the reservoir at condition x, cu. ft.
X_d	Radius of drainage of well, ft.
X_r	Radius of well bore, ft.
Y	Constant for any pressure, defined by Eq. 18
Z	Compressibility factor of reservoir gas at specified pressure and reservoir temperature, defined by Eq. 4

Subscripts

1	Refers to initial conditions of reservoir pressure and temperature.
2	Refers to bubble-point pressure and reservoir temperature.
x	Refers to any reservoir condition subsequent to the bubble-point condition.
$x - 1$	Refers to any reservoir condition immediately preceding condition x.

NOTE: The additional subscripts p and gi, used to describe L, K_g/K_o and N are defined in their appropriate reference in the nomenclature. These subscripts are used only where shown in the equations in order to distinguish between primary recovery and gas injection. Where these subscripts do not appear, the reference is only to the type of recovery process under consideration.

plans of operation, and prove sufficiently reliable, when the required data are available, for making an accurate decision as to the feasibility of gas-injection pressure maintenance.

Ample data for making the comparison from a lifting cost per barrel standpoint or most any other basis is developed by the method herein outlined.

Conclusions

Evaluations have been made in some instances wherein, from a reservoir performance standpoint alone, a gas-injection program appeared perfectly logical; yet an economic analysis of the program based on the prediction of reservoir performance as outlined herein revealed that, even with several million barrels less ultimate oil recovery, the sale of residue gas without injection was economically superior. Such a condition may be caused by the interrelationship of the many variables involved. The relationship between the price of gas and that of oil is very important in this connection.

It is admittedly next to impossible to make a forecast of the future that is certain to be absolutely reliable in and of itself. However, it has been shown herein that, irrespective of what might occur (within reasonable limits), a prediction may be made that will, with a reliable degree of accuracy, reflect the *comparative* economic benefits of a gas-injection pressure-maintenance program.

Acknowledgment

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DISCUSSION

W. Hurst*—Two observations can be made in regard to this paper. The first has already been mentioned by the author and discussed further by E. B. Armstrong, of the Honolulu Oil Co., but because of its importance in studies of gas-injection projects, it is reiterated here. This deals with the lithology of the formation. It is essential to have a comprehensive knowledge of the subsurface conditions of the reservoir, particularly the variations of permeability and porosity as can be determined from core analysis, electrical logs, and microscopic examinations of drill cuttings. The permeability profile can indicate the relative movement of oil swept out by injected gas through permeable as compared with less permeable lenses in the formation. This will give at least qualitatively the extent of gas by passing that may be anticipated through the production history of a gas-injection program.

The second point deals with the wide-scale use to which the present concept of relative permeability for two-phase and three-phase fluid flow has been applied to reservoir mechanics. Its application to gas-injection studies must be mentioned as one of many examples that have appeared in the literature for the past 10 years. Yet it cannot be overlooked that what is known today regarding relative permeabilities has been obtained in the laboratory from flow experiments on sand packs operating at pressures of only a few feet of water above atmospheric pressure, still these laboratory results have gained wide acceptance as the flow conditions prevailing in reservoirs for pressures of several thousand pounds per square inch. In this respect, this reviewer must dissent from the current belief that phenomena of multiphase fluid flow as learned in the laboratory applies to reservoir performance at high pressure. This view has been arrived at from the study of factual field data, but, most important, the capillary forces that exist at atmospheric conditions in the laboratory experiments can be markedly reduced when conditions comparable to those existing in a reservoir are considered. This should be evident from the recent paper by Katz[16] and his co-workers, who have shown that the surface tension of crude with gas dissolved in solution at 3000 psi can be reduced to the order of magnitude of 1/25 of the surface tension of the crude at atmosphere conditions. This large reduction in the surface tension of the oil has not been considered in the flow experiments hitherto conducted, and how it affects our present interpretation of relative permeability curves is still to be established. In the final analysis, our basic concept of reservoir mechanics must be acquired by high-pressure technique comparable to the conditions existing in the formation, and in this respect the engineer from his consideration of factual field data can play a prominent part.

R. H. Smith*—Mr. Patton has written an excellent and detailed paper on the methods used in analyzing field and reservoir data and evaluating the results to be expected by gas injection in volumetric type reservoirs.

During the past several years a number of such investigations have been made on such fields as Goldsmith, Slaughter, Fullerton, North Cowden, Foster-South Cowden, West Pampa and Watkins in Texas, Monument and Lovington in New Mexico, West Edmond and West Cement in Oklahoma, Rangely, Colorado, Elk Basin in Wyoming and Montana, and Haynesville, Holly Ridge and Lake St. John in Louisiana.

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* Shell Oil Co., Inc., Houston, Texas.

[16] D. L. Katz, R. R. Monroe and R. P. Trainer: Surface Tension of Crude Oils Containing Dissolved Gases. *Petr. Tech.* AIME (Sept. 1943—TP 1624).

* Dowell Inc., Houston, Texas.

In the majority of these fields the investigations have been made by an engineering committee and the results have been furnished to the operators in the various fields in the form of an engineering report. Usually only the supporting data and results are included in such reports and, to my knowledge, the methods discussed by Mr. Patton, which are used in making a complete analysis of such a project, have not been published; however, considerable information is available in some phases of such a study. It would be a valuable addition to a paper of this type to include in it sample calculations of the various formulas used, although to have done so in this particular paper would probably have made it too long for publication in *Petroleum Technology*.

It must be realized that each field will differ widely in reservoir characteristics and performance and, therefore, studies of this type will never become routine but will require careful analysis of all available information.

Because of the heterogeneous nature of limestone and dolomite porosity and permeability the performance characteristics of reservoirs of this type under both primary and gas injection are entirely different than those containing uniform sand. It is, therefore, necessary in such reservoirs that estimates of reserves and predictions of future behavior be based largely on observations made from reservoir-performance data. It then follows that the accuracy of these estimates will depend upon the precision with which production and reservoir data are obtained.

A better understanding of three-phase fluid flow has developed through relative permeability calculations made from actual reservoir performance. By determining the relationships between K_g/K_o and the liquid saturation remaining in the reservoir at any stage of depletion, it is possible to judge the efficiency of the recovery mechanism. While such data are available on a number of fields under primary operations, it is unfortunate that very little such information is available in fields where gas-injection operations are being carried on, particularly in limestone fields.

The so-called conformance factor has been introduced to recognize that injected gas in the average limestone pool would travel through zones of better developed permeability and will exert very little effective force on removing oil out of the more dense, massive limestone. In a sand of relative uniform porosity and permeability, such a conformance factor would not be used predicated on the probability that gas would actually serve as an effective force through all parts of the reservoir. It is my opinion that the use of performance data in limestone pools to establish K_g/K_o relationship automatically includes for the most part any correction or any adjustment that might be required because of the nature of porosity and permeability. It must be remembered that in the type of limestone pool discussed, the type of gas-injection programs analyzed are primarily "controlled pressure decline" programs, which, in effect, maintain the maximum amount of gas reserves commensurate with economics of handling gas that can be cycled through the zones of the better developed permeability and porosity, removing from those zones the oil originally included therein together with the oil that is gradually fed into the zones from adjacent massive limestone blocks, the movement of which is created by a combination of the forces of gravity and pressure differential from the innermost parts to the lower pressure, more permeable avenue.

Observation of recent performance data indicates to me that we are being unduly conservative when we assume that we have to introduce the so-called conformance factor in order to make this analysis more correct. We may find from actual performance data that a properly controlled gas-injection program may be more efficient and more practicable in some of our limestone sections than in sand sections of uniform porosity and permeability.

The effect of major assumptions on the final answer in a study of this type is very important. Muskat, Tarner and others have shown the results obtained by varying the values of some of the more important assumptions. Probably the most critical phase of a reservoir study, and the one that usually determines the final economics, is the conversion of calculated data with varying cumulative production in time. This calculation is made using data that are largely assumed or roughly calculated from information that is doubtful at best.

H. Pistole*—I want to congratulate Mr. Patton on the manner in which he has prepared and presented a comprehensive description of the procedure employed in an economic evaluation of future operations in dissolved-gas-drive reservoirs. It appears desirable to emphasize again that reliable quantitative reservoir studies require that a systematic process for collecting factual data be set up early in the life of a field. In this connection, comprehensive papers of this type should prove very valuable to field engineering committees in determining the type of information to be gathered jointly or in making joint analyses of the probable benefits of gas return.

With respect to the economic phase of the study, it might be pointed out that the difference in operating cost between flowing and pumping production is usually a major factor in the comparative economics of operation with and without gas return, and that the evaluation of this factor deserves the same careful engineering study as is given the reservoir performance. Finally, it might be mentioned that where corrosive fluids are produced and production is to be limited by size of gas processing and compressing equipment, care should be exercised in selecting plant size to ensure that the life of the field is not extended sufficiently for corrosion of subsurface and surface equipment to wipe out the economic benefits of the operation.

C. C. Miller†—Mr. Patton has prepared an excellent paper organizing and summarizing the necessary basic information to conduct a material-balance study. The manner in which he describes the procedure to be followed even as regards incidental details makes his paper a good work plan for this type of calculation. He has very appropriately stressed the fact that by maintaining high well productivity and preventing reduction in allowable because of a lack of market for gas, the increased production rates and deferment of the pumping stage may be sufficiently attractive to justify gas injection, even if there were no increase in ultimate recovery.

Concerning the material-balance equation, I was interested in the conversion of the quantity of produced gas from reservoir conditions to separator conditions. At times the discrepancy in gas-oil ratio between these conditions is large.

There is a question in my mind that water drive can be neglected in material-balance calculations simply because the formation is tight. Although probably inadequate for complete pressure maintenance, the rate of water influx may become large in relation to the rate of production as the reservoir pressure declines, to produce a large driving potential.

A second effect in a tight formation, as Mr. Patton has mentioned, is to produce large pressure gradients within the field. In an initially undersaturated formation, a single volumetric average pressure may not be representative because of the difference in compressibility of the materials in different sections of the formation. In addition, the migration of oil and gas to low-pressure regions will alter the saturation conditions calculated on a unit volume basis. This may explain, at least in part, the difference between field gas-oil ratios and ratios estimated from laboratory data, when it is remembered that a small change in saturation will materially alter the estimated ratios. The same effect will change the estimated productivity indexes in the low-pressure regions.

These points raise several questions:

1. Do you propose that only the oil within the MPA boundary rather than the total initial in place oil be considered in the material-balance calculation?

2. After making the proposed adjustments of the basic data—for example, the relative permeability curve—can future decline in well productivity be forecast reasonably accurately? Are estimated productivity indexes higher or lower than the observed values?

E. C. Patton, Jr. (author's reply)—With reference to Mr. Charles C. Miller's statement, "There is a question in my mind that water drive can be neglected in material-balance calculations simply because the formation is tight," the writer wishes to point out that the paper does not state that water drive could be neglected simply because the formation is tight. The limitation made as to the type reservoir to which the calculations in this paper apply was that the reservoir should have a low order of permeability and should be under volumetric control. While the first limitation alone does not necessarily exclude water-drive reservoirs, the second limitation of itself automatically eliminates water-drive reservoirs as well as gas-cap drive reservoirs. Many volumetric reservoirs are of a low order of permeability.

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Some of the more specific principles set forth in this paper are limited to *tight* volumetric reservoirs inasmuch as a more permeable reservoir initially under volumetric control, and into which gas is injected, might require a different approach, because, with a higher order of permeability, the injection of gas might artificially create a gas cap. As stated in the paper, the evaluation of the benefits of pressure maintenance by means of gas-cap injection would require a slightly different approach than that herein set out.

With regard to the first question raised by Mr. Miller, the writer wishes to state that in the paper it was noted that the M.D.A. line selected for actual use should be chosen slightly outside the one given directly by calculation because of the effect of the oil outside the calculated M.D.A. line, which might drain into the calculated M.D.A. and thereby affect the pressure therein. It was proposed therefore that neither the oil in place only within the *calculated* M.D.A. boundary nor the total oil in place out to the zero isopach line should be used, but rather some value lying between these two values and chosen on the basis of the foregoing possibilities.

In answer to the second question, the writer wishes to state that, given a sufficient amount of accurate data, future decline in productivity indexes, it is believed, can be forecast with reasonable accuracy. Calculated decline of productivity indexes may be either high or low, depending upon how the data are handled in averaging, and so forth.

With reference to the discussions by Messrs. R. H. Smith and William Hurst, the writer feels that both these discussers' comments with regard to relative permeability data are very valuable and more or less in line with statements made in the paper. Apparently Mr. Hurst advocates refinement of the laboratory determinations of relative permeability data whereby these measurements will be made under pressure and temperature conditions comparable to those encountered in actual reservoirs. As previously pointed out by the writer, this may influence the laboratory results obtained, and such determinations under simulated reservoir conditions would certainly be worth while. On the other hand, Mr. Smith apparently advocates the use of field-performance data on relative permeability, which, if available, is after all the true test of the reliability of laboratory determinations, provided the field data are accurate. As previously pointed out by the writer, considerable difference usually exists between data on relative permeability as determined by present laboratory methods and from field performance. One purpose of introducing the conformance factor was, in the application of relative permeability data to the material-balance equation, to reconcile the differences between actual field performance and theoretically predicted behavior based on laboratory data.

Volumetric Behavior of Oil and Gas from Several San Joaquin Valley Fields

By B. H. Sage* and R. H. Olds,† Members AIME

(Los Angeles Meeting, October 1946)

Abstract

The formation volume and volume of the liquid phase of oil and gas obtained from four fields in the San Joaquin Valley have been investigated at pressures, temperature, and gas-oil ratios comparable to those encountered in underground reservoirs. All the fields covered in this investigation yielded a product of a gas-oil ratio in excess of 5000 cu ft per barrel and the gravity of the tank oil for the four fields in question varied between 52° and 63° API. The results of the investigation, together with analytical data concerning the composition of the oil and gas, are submitted in tabular form. Rough correlations of the formation volume as a function of pressure, temperature, and gas-oil ratio and of the retrograde dew-point pressure as a function of gas-oil ratio, temperature, and gravity of tank oil are presented. It was not found feasible to correlate simply the formation volume of the liquid phase as a function of the applicable variable. It is desired to emphasize that these correlations are considered applicable only to the range of conditions covered in this investigation and for systems of similar nature and composition.

Introduction

Information concerning the physical properties of mixtures of oil and gas from particular fields have often been employed in predicting the situations obtaining in underground reservoirs. One of the earlier studies of this nature was the work of Beecher and Parkhurst,[1] while a more recent study of the Dominguez Field[2] presented detailed volumetric data in the two-phase as well as in the single-phase regions. Although these studies were confined to individual fields, their results proved of value in application to other fields. It has recently been shown [3,4] that it is possible in the region of low gas-oil ratios* to correlate the volumetric behavior of naturally occurring hydrocarbon mixtures from a single geographical area with sufficient accuracy to be of industrial value. For this reason it is considered of interest to submit information concerning the volumetric behavior of oil and gas mixtures from four different fields in the San Joaquin Valley and, in combination with similar published data[5] concerning mixtures of oil and gas from the Paloma field in the same area, to show rough correlations between the composition and the behavior of materials from these fields. This effort seems particularly worth while since all of the

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[1] References are at the end of the paper.

* For the purpose of this paper the region of low gas-oil ratios is considered to include those less than 3000 cu ft per barrel while the region of high gas-oil ratios is considered as comprising those greater than 5000 cu ft per barrel. In the intermediate region between 3000 and 5000 cu ft per barrel, phenomena associated with the critical state are often encountered in naturally occurring hydrocarbon mixtures at the temperatures and pressures prevalent in underground reservoirs.

mixtures in the present study have high gas-oil ratios and there still exists much uncertainty in connection with the prediction of the behavior of naturally occurring hydrocarbon mixtures in the region of retrograde phase behavior.[6–9]

TERMINOLOGY

Throughout this discussion specific meanings will be ascribed to certain words or groups of words, which may not commonly be associated with these words or phrases. The liquid-phase and gas-phase hydrocarbon samples obtained from the primary surface separator of a well will be designated as "trap liquid" and "trap gas," respectively. These comprise the constituents[10] that were combined in various proportions to produce the mixtures involved in the volumetric study. The term "tank oil" will be applied to material considered as typical of the hydrocarbon liquid delivered to the stock tank of a well. The properties of this material undoubtedly vary with trapping conditions even though the composition of the mixture produced from the well is invariant.

The "gas-oil ratio" of a mixture represents the number of cubic feet of gas associated with a barrel of oil, both volumes being measured at 60°F and 14.73 psia.* The numerical value of the gas-oil ratio for a material of given composition is dependent upon the nature of the constituents chosen. For field operations the gas-oil ratio is usually based on the ratio of the production rates of separator gas and tank oil. However, variations in separator conditions introduce some uncertainty into the specification of the composition of a naturally occurring mixture by means of the gas-oil ratio. For some purposes computation of gas-oil ratios upon the basis of an arbitrary separation of the components of the mixture into gaseous and liquid constituents is gaining acceptance. This practice appears desirable for its significance to refinery practice and because, regardless of surface separator conditions and operations, it yields a unique value for the gas-oil ratio corresponding to a particular composition. However, in view of the desire to make the results as nearly applicable to field practice as is feasible, gas-oil ratios in this paper will be expressed in terms of the separator gas and tank oil.

The "formation volume" is the ratio of the volume of a mixture, measured at the pressure and temperature in question, to the volume of the tank oil associated with that mixture, the volume of the tank oil being measured at 60°F and 14.73 psia. The numerical value of the formation volume depends upon the material selected as oil, and in this paper the tank oil is used as the basis for computing the formation volume. The "liquid volume" is the number of cubic feet of liquid phase associated with one pound of mixture measured at the conditions under consideration. The liquid volume should not be confused with the specific volume of the liquid phase, the latter quantity being the volume of one pound of the liquid phase. The definition of the "liquid formation volume" is analogous to that of the formation volume. It is the ratio of the volume of the liquid phase of the mixture, at the temperature and pressure in question, to the volume of tank oil associated with that mixture, the tank oil being measured at 60°F and 14.73 psia. It should be realized that throughout the heterogeneous region the formation volume is larger than and distinct from the liquid formation volume. However, at the bubble point they become identical and remain so throughout the condensed liquid region, while at the dew point the liquid formation volume vanishes.

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* Throughout this paper all pressures are expressed in pounds per square inch absolute.

MATERIALS

Samples of trap gas and trap liquid were obtained from wells in four different fields in the San Joaquin Valley. The samples were collected in forged-steel containers, which were equipped with valve ports at both ends and were thoroughly purged by flushing with a large excess of the fluids collected. Upon arrival at the laboratory the sample containers were tested for signs of leakage, and subsamples were obtained by withdrawing the hydrocarbons through drying chambers packed with granular calcium chloride into appropriate subsample containers. By the introduction of ethylene glycol the pressure within the liquid-sample containers was maintained above the initial trapping pressure during the withdrawal process. To ensure the vaporization of any condensate that may have been present, the trap gas was withdrawn from the original sample container at a temperature above 200°F. The subsamples were forwarded to industrial laboratories, where the compositions of the trap liquid and trap gas for each field were determined by fractional distillation.

In Table 1 are presented the compositions of the trap liquid and trap gas for each of the four restricted[11] multicomponent systems investigated. The data have been presented on both a molal and a weight basis. The average molecular weight of the heavier portion of the trap gas was estimated, while that of the trap liquid was determined from the freezing-point lowering of benzene. In Table 2 some properties of the heavier portion of the trap liquid are recorded. It should be noted that in Table 2 the weight fractions recorded are based upon a unit weight of trap liquid and total only to that fraction of the trap liquid represented by the heavier portion. The heavier portion of the trap liquid was separated by fractional distillation into several parts of relatively narrow boiling ranges. These fractionations were carried out at reduced pressures in order to avoid decomposition of the high molecular weight hydrocarbons through overheating.

In Table 3 are recorded the compositions of the tank oils as established from appropriate analyses of the liquid-phase samples from the stock tanks of the wells.

LABORATORY APPROACH

The equipment and techniques employed in studies of this nature have been described in the literature[5,12,13] and no fundamental modifications were necessary for the present investigation.

The compositions of the experimentally studied mixtures are recorded in Table 4 for each of the systems investigated. These data were computed from a knowledge of the relative weights of the trap liquid and trap gas used in preparing the mixtures.

EXPERIMENTAL RESULTS

In Tables 5 and 6 are recorded, for system B, the compressibility factor of the trap gas and the specific volume and liquid volume of the trap liquid.

The volumetric behavior of the mixtures for each of the systems investigated is reported in Tables 7 to 10 inclusive. For each mixture the compressibility factor, specific volume, liquid volume when present, formation volume, and liquid formation volume have been recorded. The two-phase region covered by this investigation involved only that portion in which retrograde phase behavior is observed. Hence, all two-phase boundary values of pressure, compressibility factor, volume, and formation volume are herein designated as retrograde dew-point values.

CORRELATIONS

The graphic representation of the influences of pressures and temperature upon the variables recorded in Tables 7 to 10 for a particular field has already been published,[5] therefore the effects of pressure and temperature are not stressed in the present work. The primary emphasis is placed upon the relation of the volumetric and phase behavior of the mixtures to the compositions of the mixtures and to the properties of the constituents of which the mixtures are composed.

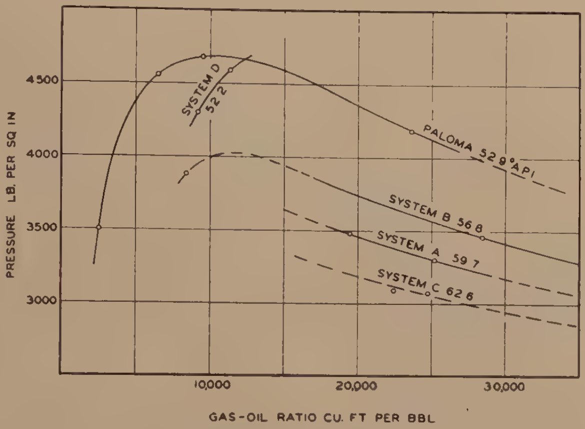

FIG 1—INFLUENCE OF GAS-OIL RATIO AND TANK-OIL GRAVITY UPON RETROGRADE DEW-POINT PRESSURE AT 160°F.

In Fig 1 curves are shown relating the retrograde dew-point pressure to the gas-oil ratio at 160°F for each of the four mixtures reported in Tables 7 to 10. Included in the diagram are similar data from an earlier investigation[5] of materials from the Paloma field. For some fields there are insufficient data to establish the relationship except by analogy. The dotted portions of the curves represent estimates of the behaviors of the systems for which incomplete experimental data are available. The gravities in degrees API of the tank oils corresponding to the various systems are shown beside each curve. These data indicate an apparent correlation between the gravity of the tank oil and the retrograde dew-point pressure. Similar diagrams were made for other temperatures and the same general relationships were noted in each case.

On the basis of these correlations, the data presented in Table 11 were obtained, relating the retrograde dew-point pressure to the gas-oil ratio and tank-oil gravity.

It should be realized that the experimental data upon which the information in Table 11 is based are rather sparse, and it is unlikely that the information presented can be extrapolated with any reasonable degree of accuracy outside the ranges of gas-oil ratio and tank-oil gravity included in the tabulation.

In Fig 2 is presented the formation volume as a function of gas-oil ratio for several pressures at a temperature of 100°F. The data confirm earlier investigations[2] showing that there is a nearly linear relationship between formation volume and gas-oil ratio throughout the heterogeneous region of a multicomponent naturally occurring hydrocarbon mixture. On the basis of the information presented in Tables 7 to 10, which yield correlations at all temperatures comparable to that shown in Fig 2, the formation volume is considered a single valued function of gas-oil ratio, temperature, and pressure for the purpose of roughly correlating the data. The following equation represents an empirical relationship between the formation volume,

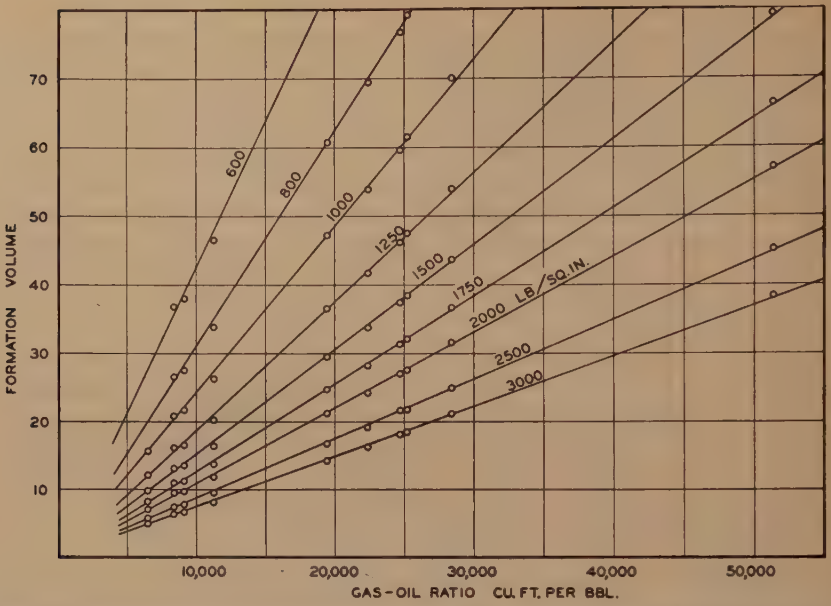

FIG 2—ISOBARIC RELATIONS BETWEEN FORMATION VOLUME AND GAS-OIL RATIO AT 100°F.

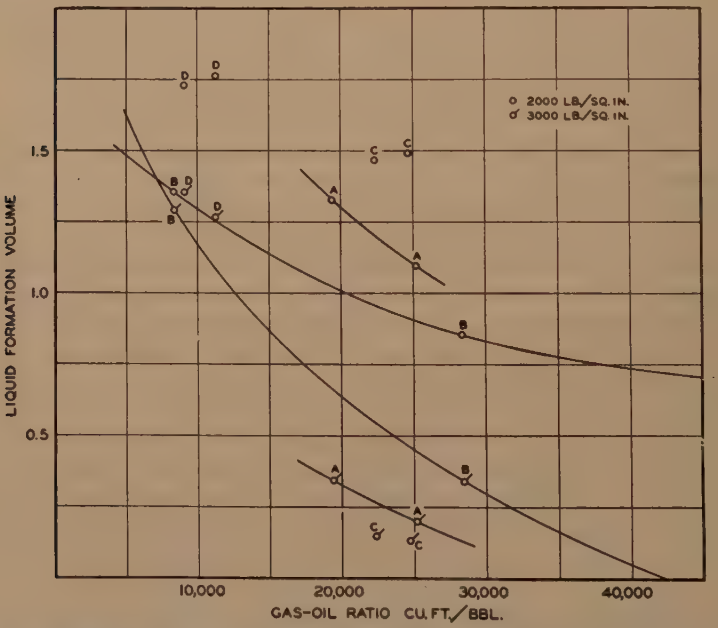

FIG 3—RELATION BETWEEN LIQUID FORMATION VOLUME AND GAS-OIL RATIO AT 100°F FOR VARIOUS SYSTEMS AT 2000 AND 3000 POUNDS PER SQUARE INCH ABSOLUTE.

gas-oil ratio, pressure and temperature:

$$v = A \frac{rT}{P} \qquad [1]$$

Values for the coefficient A in Eq 1 are given in Table 12. Since A is a function of temperature and pressure, it is obvious that in Eq 1 the ratio T/P could have been included in A. However, by writing the equation as shown, the variation of A with temperature and pressure is small, thus facilitating the estimation of values for A for states between those given in the table.

Eq 1 is valid only for gas-oil ratios greater than 5000 cu ft per barrel, and serious discrepancies are likely to be encountered in its application at lower gas-oil ratios. It should be emphasized that the applicability of Eq 1 utilizing the coefficient values given in Table 12 is restricted to systems similar to those reported in Tables 7 to 10, inclusive. Furthermore, this correlation does not describe with great accuracy the behavior of the individual mixtures used in its preparation. In Table 13 are recorded for comparison several values of the experimentally observed and empirically computed formation volume. It is apparent that significant differences between the two sets of values exist at a number of states. However, it is believed that the values obtained by application of Eq 1 are sufficiently descriptive of actuality to be useful in situations where experimental data are not available.

In Fig 3 the variation of the liquid formation volume with gas-oil ratio is shown for two pressures at 100°F. There does not appear to be any simple systematic correlation between the characteristics of the systems and relationship of liquid formation volume to gas-oil ratio, hence no attempt to correlate these data is presented here.

Other investigations have shown that with an accuracy sufficient for most engineering purposes the volumetric and phase behavior of naturally occurring hydrocarbon mixtures in the region of low gas-oil ratios may be correlated with quantities pertaining to the compositions of the mixtures and to the properties of the constituents of which the mixtures are composed.

The present work demonstrates for materials from San Joaquin Valley fields a simple correlation between the formation volume in the heterogeneous region and the gas-oil ratio for gas-oil ratios greater than 5000 cu ft per barrel. In addition, for limited ranges of the variables, a correlation is shown relating the gas-oil ratio and tank-oil gravity to the retrograde dew-point pressure. However, no relationship was derived by which the relative volumes of the gas and liquid phases in the heterogeneous region may be predicted from a knowledge of the compositions of the mixtures and properties of the constituents.

ACKNOWLEDGMENTS

Financial support for this work was provided by the Texaco Development Corporation, the General Petroleum Corporation, the Richfield Oil Corporation, and the Union Oil Company. The interest and cooperation of these concerns have made possible the successful completion of the work, and the analyses reported in the first part of this paper were carried out in the laboratories of the several corporations.

NOMENCLATURE

A, empirical coefficient in Equation 1.

P, pressure, psia.

r, gas-oil ratio, cu ft per barrel.

T, absolute temperature, deg R. (deg F + 459.69).

v, formation volume.

TABLES

Tables 1 to 13 appear on pages 163 to 173.

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DISCUSSION

M. B. STANDING.*—The authors have presented an excellent paper on the behavior of naturally occurring condensate systems, both from the viewpoint of the field engineer who is interested primarily in the formation-volume data but also from the viewpoint of the technologist who is interested in phase behavior of such systems.

To me, one interesting feature of the paper is how well the two-phase formation-volume factor can be estimated from the pressure, temperature, and gas-oil ratio of the production, and the factor A.

Table 12 gives values of the coefficient A as a function of only pressure and temperature. Now, actually, the units of A represent the volume (bbl.) of the mixture in the formation per cubic feet of surface gas times the ratio P/T. Considering the fact that A therefore includes both the variation in the gas-law deviation factor Z (which in itself varies with the gas gravity, oil gravity and molecular weight, and gas-oil ratio of the mixture) and the volumetric behavior of the condensed liquid phase, it is gratifying to find that A remains as constant as it does.

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* Standard Oil Company of California.

TABLE 1—*Composition of Trap Samples*

Component	Gas		Liquid	
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
System A				
Methane	0.8861	0.7352	0.0701	0.0136
Ethane	0.0430	0.0669	0.0405	0.0147
Propane	0.0296	0.0675	0.1020	0.0543
Isobutane	0.0118	0.0355	0.0683	0.0480
n-butane	0.0232	0.0697	0.1162	0.0816
Isopentane	0.0023	0.0086	0.0500	0.0436
n-pentane	0.0021	0.0078	0.0632	0.0551
Isohexane	0.0006	0.0027	0.0375	0.0391
n-hexane	0.0009	0.0040	0.0740	0.0771
Heptanes	0.0004	0.0021	0.0885	0.1072
Octanes and heavier	[a]		0.2897[b]	0.4657
System B				
Methane	0.8953	0.7588	0.1029	0.0184
Ethane	0.0485	0.0769	0.0291	0.0098
Propane	0.0201	0.0469	0.0324	0.0160
Isobutane	0.0039	0.0120	0.0138	0.0090
n-butane	0.0068	0.0209	0.0326	0.0212
Isopentane	0.0024	0.0091	0.0244	0.0197
n-pentane	0.0020	0.0076	0.0306	0.0246
Carbon dioxide	0.0140	0.0326	0.0031	0.0015
Hexanes and heavier	0.0070[c]	0.0352	0.7311[d]	0.8798
System C				
Methane	0.8573	0.6805	0.0503	0.0091
Ethane	0.0519	0.0772	0.0118	0.0040
Propane	0.0470	0.1025	0.0584	0.0290
Isobutane	0.0113	0.0325	0.0429	0.0281
n-butane	0.0147	0.0423	0.0858	0.0562
Isopentane	0.0059	0.0211	0.0667	0.0542
n-pentane	0.0044	0.0157	0.0828	0.0673
Iso hexane	0.0009	0.0038	0.0581	0.0564
n-hexane	0.0036	0.0153	0.1720	0.1670
Heptanes	0.0009	0.0045	0.0775	0.0875
Carbon dioxide	0.0021	0.0046	0.0014	0.0007
Octanes and heavier	[e]		0.2923[f]	0.4405
System D				
Methane	0.8522	0.6863	0.0866	0.0143
Ethane	0.0629	0.0949	0.0419	0.0129
Propane	0.0418	0.0926	0.0852	0.0386
Isobutane	0.0073	0.0213	0.0373	0.0222
n-butane	0.0149	0.0433	0.0872	0.0520
Isopentane	0.0039	0.0139	0.0513	0.0380
n-pentane	0.0028	0.0102	0.0496	0.0367
Hexanes	0.0011	0.0049	0.0993	0.0878
Heptanes	0.0008	0.0040	0.1393	0.1432
Carbon dioxide	0.0120	0.0256		
Octanes and heavier	0.0003[g]	0.0021	0.3223[h]	0.5543

Average molecular weights of less-volatile constituents:

[a] Omitted from original analysis.
[b] 133.
[c] 95.
[d] 107.7.
[e] Omitted from original analysis.
[f] 133.7.
[g] 120.
[h] 167.6.

TABLE 2—*Properties of Less Volatile Portion of Trap-liquid Samples*

System	A	B	C	D
Sp gr at 60°F, atmospheric pressure	0.7861	0.7690	0.7800	0.8134
Average molecular weight	133	107.7	133.7	167.6
Kinematic viscosity, centistokes:				
77°F	1.122	0.71	1.003	
100°F	0.957	0.82	0.865	
Viscosity gravity factor	0.816	0.811	0.815	0.831

Cut No.	Specific Gravity 60°F	Kinematic Viscosity, Centistokes		Viscosity Gravity Factor	Average Boiling Point, Deg F	Weight[a] Fraction
		77°F	100°F			
System A						
1	0.7507	0.7012	0.6177	0.7971	222	0.07426
2	0.7587	0.7639	0.6694	0.8018	248	0.07506
3	0.7674	0.8417	0.7346	0.8073	275	0.07592
4	0.7805	0.9926	0.8536	0.8150	312	0.07721
5	0.8049	1.4937	1.2390	0.8267	377	0.07963
Residue	0.8453	4.9882	3.6658	0.8362		0.08362
System B						
1	0.7161	0.54	0.48	0.770	175	0.08292
2	0.7320	0.58	0.52	0.784	189	0.08458
3	0.7459	0.63	0.56	0.797	206	0.08619
4	0.7571	0.67	0.59	0.807	228	0.08748
5	0.7653	0.71	0.62	0.814	249	0.08843
6	0.7741	0.78	0.68	0.820	270	0.08945
7	0.7826	0.86	0.75	0.824	293	0.09043
8	0.7905	1.00	0.85	0.827	324	0.09044
9	0.8026	1.31	1.10	0.829	367	0.09182
Residue	0.8324	2.55	2.03	0.840	450	0.08806
System C						
1	0.7424	0.679	0.601	0.7882	202	0.0698
2	0.7531	0.718	0.632	0.7981	229	0.0708
3	0.7645	0.794	0.695	0.8070	263	0.0718
4	0.7818	0.926	0.805	0.8200	300	0.0735
5	0.8031	1.306	1.099	0.8298	359	0.0754
Residue	0.8423	3.584	2.733	0.8416		0.0792
System D						
1	0.7588	0.7907	0.6851	0.8008	225–260	0.05166
2	0.7621	0.8173	0.7104	0.8032	260–278	0.05189
3	0.7723	0.8905	0.7685	0.8110	278–296	0.05258
4	0.7854	1.0285	0.8620	0.8206	296–330	0.05347
5	0.7979	1.2887	1.0931	0.8241	330–370	0.05432
6	0.8154	1.6454	1.3506	0.8355	370–425	0.05552
7	0.8338	2.6186	2.0643	0.8407	425–477	0.05677
8	0.8516	4.5038	3.2760	0.8465	477–552	0.05798
Residue	0.8820	3411.9	2224.4		552	0.12011

[a] Based upon entire trap-liquid sample.

TABLE 3—*Composition of Tank Oil*

Component	Mol Fraction	Weight Fraction
System A[a]		
Methane		
Ethane		
Propane	0.0019	0.0008
Isobutane	0.0253	0.0136
n-butane	0.0222	0.0119
Isopentane	0.0677	0.0451
n-pentane	0.0637	0.0424
Isohexane	0.0608	0.0484
n-hexane	0.1128	0.0897
Heptanes	0.1467	0.1357
Octanes and heavier	0.4989	0.6124
System B[b]		
Methane	0.0003	0.0001
Ethane	0.0028	0.0008
Propane	0.0134	0.0058
Isobutane	0.0109	0.0062
n-butane	0.0350	0.0200
Isopentane	0.0322	0.0228
n-pentane	0.0407	0.0289
Carbon dioxide hexanes +	0.8647	0.9154
System C[c]		
Methane	0.0002	0.0000
Ethane	0.0009	0.0003
Propane	0.0339	0.0147
Isobutane	0.0366	0.0209
n-butane	0.0780	0.0446
Isopentane	0.0632	0.0448
n-pentane	0.0764	0.0542
Isohexane	0.0434	0.0368
n-hexane	0.1520	0.1288
Heptanes	0.0690	0.0680
Octanes and heavier	0.4464	0.5860
System D[d]		
Methane		
Ethane		
Propane	0.0122	0.0043
Isobutane	0.0149	0.0070
n-butane	0.0566	0.0265
Isopentane	0.0536	0.0312
n-pentane	0.0523	0.0304
Hexanes	0.1290	0.0897
Heptanes	0.2027	0.1638
Octanes and heavier	0.4787	0.6471

Gravities of the tank oils:
[a] 59.7° API.
[b] 56.8° API.
[c] 62.6° API.
[d] 52.2° API.

TABLE 4—*Compositions of Experimentally Studied Mixtures*

Component	Weight Fraction Trap Gas			
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
System A				
	0.7388		0.7870	
Methane	0.8238	0.5467	0.8376	0.5815
Ethane	0.0428	0.0532	0.0429	0.0558
Propane	0.0351	0.0641	0.0339	0.0647
Isobutane	0.0161	0.0387	0.0152	0.0381
n-butane	0.0303	0.0729	0.0287	0.0723
Isopentane	0.0060	0.0177	0.0051	0.0160
n-pentane	0.0068	0.0202	0.0057	0.0179
Isohexane	0.0034	0.0121	0.0028	0.0104
n-hexane	0.0065	0.0231	0.0053	0.0196
Heptanes	0.0071	0.0295	0.0056	0.0245
Octanes and heavier	0.0221	0.1212	0.0172	0.0992
Gas-oil ratio	19,410		25,161	
System C				
	0.7755		0.7924	
Methane	0.8074	0.5298	0.8119	0.5411
Ethane	0.0494	0.0608	0.0496	0.0620
Propane	0.0477	0.0860	0.0476	0.0873
Isobutane	0.0132	0.0315	0.0131	0.0316
n-butane	0.0191	0.0454	0.0187	0.0452
Isopentane	0.0097	0.0285	0.0093	0.0279
n-pentane	0.0092	0.0273	0.0088	0.0264
Hexanes	0.0185	0.0650	0.0172	0.0616
Heptanes	0.0056	0.0231	0.0052	0.0217
Carbon dioxide	0.0021	0.0037	0.0021	0.0033
Octanes and heavier	0.0181	0.0989	0.0165	0.0914
Gas-oil ratio	22,356		24,661	
System D				
	0.5938		0.6454	
Methane	0.7582	0.4133	0.7749	0.4480
Ethane	0.0603	0.0616	0.0607	0.0658
Propane	0.0471	0.0706	0.0462	0.0734
Isobutane	0.0111	0.0217	0.0103	0.0217
n-butane	0.0237	0.0469	0.0222	0.0464
Isopentane	0.0097	0.0237	0.0086	0.0225
n-pentane	0.0086	0.0210	0.0076	0.0196
Hexanes	0.0132	0.0386	0.0111	0.0343
Heptanes	0.0178	0.0605	0.0148	0.0533
Carbon dioxide	0.0105	0.0157	0.0108	0.0171
Octanes and heavier	0.0398	0.2264	0.0328	0 1979
Gas-oil ratio	9091		11,226	

System B

Component	Weight Fraction Trap Gas							
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
	0.5956		0.8351		0.9019		0.9662	
Methane	0.7964	0.4594	0.8642	0.6367	0.8782	0.6862	0.8903	0.7337
Ethane	0.0460	0.0498	0.0477	0.0659	0.0480	0.0704	0.0483	0.0747
Propane	0.0217	0.0344	0.0206	0 0418	0.0204	0.0438	0.0202	0.0458
Isobutane	0.0051	0.0108	0.0043	0.0115	0.0041	0.0117	0.0040	0.0119
n-butane	0.0101	0.0210	0.0078	0.0209	0.0074	0.0209	0.0070	0.0209
Isopentane	0.0052	0.0134	0.0033	0.0109	0.0029	0.0102	0.0026	0.0095
n-pentane	0.0056	0.0145	0.0032	0.0104	0.0027	0.0093	0.0022	0.0082
Carbon dioxide	0 0126	0.0200	0.0136	0.0275	0.0138	0.0295	0.0139	0.0316
Hexanes and heavier	0.0973	0.3767	0.0353	0.1744	0.0225	0.1180	0.0115	0.0637
Gas-oil ratio	8,374		28,350		51,330		159,160	

TABLE 5—*Compressibility Factors for Trap Gas of System B*

Pressure, Psia	100°F	160°F	220°F	280°F	340°F	400°F
0	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
20	0.9974	0.9983	0.9987	0.9989	0.9992	0.9998
40	0.9945	0.9964	0.9975	0.9979	0.9988	0.9995
60	0.9918	0.9941	0.9960	0.9970	0.9981	0.9992
100	0.9865	0.9904	0.9938	0.9952	0.9971	0.9986
150	0.9794	0.9855	0.9907	0.9932	0.9960	0.9980
200	0.9725	0.9811	0.9877	0.9912	0.9948	0.9975
300	0.9590	0.9717	0.9815	0.9873	0.9924	0.9961
400	0.9455	0.9627	0.9758	0.9840	0.9902	0.9950
500	0.9325	0.9541	0.9700	0.9805	0.9882	0.9940
600	0.9200	0.9456	0.9645	0.9774	0.9864	0.9930
800	0.8950	0.9300	0.9544	0.9713	0.9830	0.9912
1000	0.8698	0.9155	0.9452	0.9660	0.9807	0.9900
1250	0.8406	0.8988	0.9350	0.9601	0.9779	0.9892
1500	0.8185	0.8849	0.9268	0.9560	0.9759	0.9897
1750	0.8014	0.8739	0.9206	0.9529	0.9749	0.9912
2000	0.7895	0.8670	0.9158	0.9514	0.9749	0.9934
2250	0.7827	0.8625	0.9150	0.9519	0.9761	0.9965
2500	0.7819	0.8612	0.9160	0.9534	0.9790	1.0000
2750	0.7877	0.8628	0.9185	0.9560	0.9832	1.0039
3000	0.7989	0.8681	0.9230	0.9600	0.9884	1.0085
3250	0.8140	0.8763	0.9291	0.9655	0.9948	1.0140
3500	0.8304	0.8869	0.9370	0.9730	1.0020	1.0203
3750	0.8482	0.8993	0.9467	0.9814	1.0090	1.0273
4000	0.8670	0.9136	0.9583	0.9915	1.0185	1.0350
4250	0.8875	0.9299	0.9709	1.0024	1.0280	1.0438
4500	0.9095	0.9470	0.9843	1.0139	1.0383	1.0530
4750	0.9335	0.9650	0.9988	1.0264	1.0491	1.0630
5000	0.9581	0.9837	1.0140	1.0395	1.0607	1.0735
5500	1.0094	1.0233	1.0463	1.0679	1.0860	1.0968
6000	1.0615	1.0648	1.0812	1.0999	1.1133	1.1218
6500	1.1141	1.1078	1.1180	1.1325	1.1416	1.1480
7000	1.1679	1.1520	1.1562	1.1656	1.1722	1.1760
7500	1.2222	1.1982	1.1947	1.1995	1.2030	1.2045
8000	1.2775	1.2449	1.2340	1.2340	1.2325	1.2325
8500	1.3339	1.2914	1.2753	1.2694	1.2653	1.2610
9000	1.3915	1.3384	1.3172	1.3053	1.2970	1.2900
9500	1.4510	1.3863	1.3599	1.3442	1.3285	1.3155
10,000		1.4340	1.4020	1.3778	1.3600	1.3478

TABLE 6—*Volumetric Behavior of Trap Liquid of System B*

Pressure, Psia	100°F		190°F		250°F	
	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb
B.P.	(303)[a] 0.02282	0.02282	(368) 0.02367	0.02367	(424) 0.02475	0.02475
100	0.04770	0.0215		0.0217		0.0217
200	0.03228	0.0222	0.04105	0.0226	0.05280	0.0228
400	0.02279		0.02368		0.02705	0.0246
600	0.02274		0.02360		0.02465	
800	0.02268		0.02354		0.02455	
1000	0.02264		0.02345		0.02444	
1250	0.02256		0.02337		0.02430	
1500	0.02250		0.02328		0.02419	
1750	0.02245		0.02320		0.02407	
2000	0.02239		0.02312		0.02396	
2250	0.02233		0.02304		0.02387	
2500	0.02225		0.02296		0.02379	
2750	0.02219		0.02290		0.02370	
3000	0.02212		0.02284		0.02364	
3250	0.02205		0.02279		0.02357	
3500	0.02198		0.02273		0.02351	

[a] Figures in parentheses represent bubble-point pressures expressed as pounds per square inch absolute.

TABLE 7—*Volumetric Behavior of Experimentally Studied Mixtures for System A*

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.7388 Gas-oil Ratio = 19,410 Cu Ft per Bbl					
40°F					
R.D.P.	(3095)[a] 0.6815	0.04885	0	11.351	0
200	0.9205	1.0210		237.25	
400	0.8626	0.4784		111.17	
600	0.8168	0.3020	0.00703	70.18	1.634
800	0.7771	0.21549	0.00752	50.07	1.747
1000	0.7413	0.16445	0.00789	38.21	1.833
1250	0.6995	0.12414	0.00820	28.85	1.905
1500	0.6643	0.09825	0.00829	22.83	1.926
1750	0.6369	0.08074	0.00804	18.762	1.868
2000	0.6203	0.06880	0.00731	15.987	1.699
2250	0.6145	0.06059	0.00590	14.079	1.371
2500	0.6225	0.05524	0.00388	12.836	0.902
2750	0.6439	0.05194	0.00178	12.069	0.414
3000	0.6705	0.04958	0.00036	11.521	0.084
3250	0.7004	0.04781		11.110	
3500	0.7335	0.04649		10.803	
3750	0.7675	0.04540		10.550	
4000	0.8015	0.04445		10.329	
4250	0.8351	0.04359		10.129	
4500	0.8686	0.04282		9.950	
4750	0.9022	0.04214		9.792	
5000	0.9360	0.04153		9.650	
100°F					
R.D.P.	(3394) 0.7670	0.05615	0	13.048	0
200	0.9474	1.1770		273.5	
400	0.9050	0.5622		130.64	
600	0.8708	0.3606	0.00539	83.79	1.252
800	0.8420	0.2615	0.00577	60.77	1.341
1000	0.8172	0.20306	0.00604	47.19	1.404
1250	0.7900	0.15704	0.00622	36.49	1.445
1500	0.7665	0.12697	0.00626	29.50	1.455
1750	0.7470	0.10607	0.00613	24.648	1.424
2000	0.7336	0.09114	0.00573	21.178	1.331
2250	0.7250	0.08007	0.00509	18.606	1.183
2500	0.7218	0.07174	0.00416	16.670	0.967
2750	0.7252	0.06553	0.00286	15.227	0.665
3000	0.7370	0.06104	0.00147	14.184	0.342
3250	0.7543	0.05767	0.00044	13.401	0.102
3500	0.7765	0.05513		12.811	
3750	0.8010	0.05308		12.334	
4000	0.8279	0.05143		11.951	
4250	0.8560	0.05005		11.630	
4500	0.8855	0.04890		11.363	
4750	0.9148	0.04785		11.119	
5000	0.9445	0.04694		10.907	
160°F					
R.D.P.	(3480) 0.8310	0.06570	0	15.267	0
200	0.9635	1.3254		308.0	
400	0.9343	0.6426		149.32	
600	0.9100	0.4173	0.00384	96.97	0.892
800	0.8894	0.3059	0.00406	71.08	0.943
1000	0.8717	0.23982	0.00422	55.73	0.981
1250	0.8517	0.18745	0.00434	43.56	1.008
1500	0.8348	0.15311	0.00436	35.58	1.013
1750	0.8208	0.12904	0.00419	29.99	0.974
2000	0.8105	0.11149	0.00387	25.91	0.899
2250	0.8037	0.09827	0.00341	22.835	0.792
2500	0.8007	0.08811	0.00279	20.474	0.648
2750	0.8020	0.08023	0.00201	18.643	0.467
3000	0.8074	0.07404	0.00117	17.205	0.272
3250	0.8178	0.06923	0.00049	16.087	0.114
160°F (*Continued*)	(3480)				
3500	0.8322	0.06542		15.202	
3750	0.8502	0.06237		14.493	
4000	0.8701	0.05984		13.905	
4250	0.8915	0.05771		13.410	
4500	0.9143	0.05590		12.990	
4750	0.9377	0.05431		12.620	
5000	0.9618	0.05292		12.297	
220°F					
R.D.P.	(3295) 0.8768	0.08030	0	18.659	0
200	0.9790	1.4771		343.2	
400	0.9598	0.7241		168.26	
600	0.9424	0.4740	0.00234	110.14	0.544
800	0.9270	0.3497	0.00250	81.26	0.581
1000	0.9132	0.2756	0.00260	64.04	0.604
1250	0.8982	0.21683	0.00264	50.38	0.613
1500	0.8853	0.17810	0.00257	41.39	0.597
1750	0.8750	0.15088	0.00239	35.06	0.555
2000	0.8678	0.13093	0.00211	30.42	0.490
2250	0.8633	0.11578	0.00175	26.90	0.407
2500	0.8620	0.10404	0.00134	24.176	0.311
2750	0.8632	0.09472	0.00089	22.010	0.207
3000	0.8677	0.08728	0.00047	20.281	0.109
3250	0.8750	0.08124	0.00007	18.878	0.016
3500	0.8852	0.07632		17.734	
3750	0.8982	0.07228		16.796	
4000	0.9137	0.06893		16.017	
4250	0.9301	0.06604		15.346	
4500	0.9481	0.06358		14.774	
4750	0.9666	0.06141		14.270	
5000	0.9852	0.05946		13.817	
Weight Fraction Trap Gas = 0.7870 Gas-oil Ratio = 25,161 Cu Ft per Bbl					
40°F					
R.D.P.	(3010) 0.6790	0.05236	0	14.921	0
200	0.9360	1.0862		309.5	
400	0.8798	0.5105		145.47	
600	0.8313	0.3216	0.00556	91.63	1.584
800	0.7889	0.22887	0.00598	65.22	1.704
1000	0.7524	0.17462	0.00629	49.76	1.792
1250	0.7118	0.13216	0.00651	37.66	1.855
1500	0.6745	0.10436	0.00645	29.74	1.838
1750	0.6453	0.08558	0.00605	24.387	1.724
2000	0.6250	0.07253	0.00520	20.668	1.482
2250	0.6220	0.06416	0.00369	18.283	1.052
2500	0.6315	0.05863	0.00213	16.706	0.607
2750	0.6518	0.05501	0.00083	15.675	0.237
3000	0.6778	0.05244	0.00003	14.942	0.009
3250	0.7074	0.05052		14.395	
3500	0.7394	0.04903		13.972	
3750	0.7725	0.04781		13.624	
4000	0.8059	0.04676		13.325	
4250	0.8394	0.04584		13.062	
4500	0.8723	0.04499		12.820	
4750	0.9054	0.04424		12.606	
5000	0.9389	0.04358		12.419	
100°F					
R.D.P.	(3245) 0.7652	0.06130	0	17.468	0
200	0.9564	1.2431		354.2	
400	0.9184	0.5969		170.09	
600	0.8849	0.3834	0.00401	109.25	1.141
800	0.8554	0.2780	0.00428	79.22	1.220

[a] Figures in parentheses represent retrograde dew-point pressures in pounds per square inch absolute.

TABLE 7—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.7870 Gas-oil Ratio = 25,161 Cu Ft per Bbl					
100°F (*Continued*)					
	(3245)				
1000	0.8300	0.21576	0.00447	61.48	1.274
1250	0.8018	0.16675	0.00459	47.52	1.308
1500	0.7770	0.13466	0.00449	38.37	1.279
1750	0.7561	0.11232	0.00423	32.01	1.205
2000	0.7419	0.09643	0.00385	27.48	1.097
2250	0.7343	0.08484	0.00329	24.175	0.938
2500	0.7323	0.07615	0.00242	21.699	0.690
2750	0.7370	0.06967	0.00150	19.853	0.427
3000	0.7485	0.06486	0.00070	18.482	0.199
3250	0.7655	0.06123		17.448	
3500	0.7870	0.05845		16.657	
3750	0.8113	0.05624		16.026	
4000	0.8373	0.05442		15.506	
4250	0.8642	0.05286		15.063	
4500	0.8915	0.05150		14.675	
4750	0.9188	0.05028		14.329	
5000	0.9468	0.04923		14.027	
160°F					
	(3294)				
R.D.P.	0.8328	0.07277	0	20.737	0
200	0.9725	1.3995		398.8	
400	0.9463	0.6809		194.04	
600	0.9220	0.4423	0.00255	126.04	0.727
800	0.9002	0.3239	0.00282	92.30	0.804
1000	0.8813	0.2537	0.00297	72.29	0.846
1250	0.8611	0.19828	0.00300	56.50	0.855
1500	0.8449	0.16212	0.00291	46.20	0.829
1750	0.8323	0.13689	0.00270	39.01	0.770
2000	0.8229	0.11843	0.00241	33.75	0.686
2250	0.8166	0.10446	0.00201	29.77	0.573
2500	0.8140	0.09372	0.00151	26.71	0.430
2750	0.8150	0.08530	0.00100	24.307	0.285
3000	0.8205	0.07872	0.00052	22.432	0.148
3250	0.8304	0.07354	0.00008	20.956	0.023
3500	0.8448	0.06947		19.796	
3750	0.8620	0.06616		18.853	
4000	0.8811	0.06340		18.066	
4250	0.9017	0.06107		17.401	
4500	0.9232	0.05905		16.827	
4750	0.9455	0.05729		16.326	
5000	0.9681	0.05573		15.880	
220°F					
	(3073)				
R.D.P.	0.8830	0.09071	0	25.85	0
200	0.9805	1.5477		441.0	
400	0.9623	0.7595		216.42	
600	0.9460	0.4977	0.00130	141.84	0.370
800	0.9315	0.3676	0.00150	104.75	0.427
1000	0.9189	0.2901	0.00158	82.66	0.450
1250	0.9055	0.22869	0.00158	65.17	0.450
1500	0.8943	0.18822	0.00151	53.63	0.430
1750	0.8850	0.15965	0.00137	45.49	0.390
2000	0.8784	0.13865	0.00115	39.51	0.328
2250	0.8746	0.12271	0.00091	34.97	0.259
2500	0.8740	0.11036	0.00064	31.45	0.182
2750	0.8759	0.10055	0.00036	28.65	0.103
3000	0.8810	0.09271	0.00008	26.42	0.023
3250	0.8885	0.08631		24.593	
3500	0.8988	0.08107		23.102	
3750	0.9110	0.07669		21.854	
4000	0.9257	0.07306		20.819	
4250	0.9420	0.06997		19.939	
4500	0.9593	0.06730		19.178	
4750	0.9778	0.06499		18.518	
5000	0.9967	0.06293		17.933	

TABLE 8—*Volumetric Behavior of Experimentally Studied Mixtures for System B*

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.5956 Gas-oil Ratio = 8,374 Cu Ft per bbl					
100°F					
		(3900)[a]			
R.D.P.	0.7877	0.04362	0	5.368	0
600	0.830	0.299		36.80	
800	0.8042	0.2171	0.00965	26.72	1.188
1000	0.7825	0.1690	0.00990	20.80	1.218
1250	0.7593	0.1312	0.01021	16.15	1.255
1500	0.7399	0.1065	0.01050	13.11	1.292
1750	0.7251	0.08949	0.01080	11.01	1.329
2000	0.7149	0.07720	0.01100	9.500	1.354
2250	0.7093	0.06809	0.01113	8.379	1.370
2500	0.7089	0.06124	0.01110	7.536	1.366
2750	0.7130	0.05600	0.01095	6.891	1.348
3000	0.7227	0.05203	0.01054	6.403	1.297
3250	0.7371	0.04899	0.00966	6.029	1.189
3500	0.7542	0.04654	0.00800	5.727	0.985
3750	0.7746	0.04461	0.00460	5.490	0.5661
4000	0.7964	0.04300		5.292	
4250	0.8209	0.04172		5.134	
190°F					
		(3850)			
R.D.P.	0.8450	0.05503	0	6.772	0
600	0.876	0.3660		45.04	
800	0.8609	0.2688	0.00785	33.08	0.9660
1000	0.8484	0.2127	0.00806	26.18	0.9919
1250	0.8352	0.1675	0.00835	20.61	1.028
1500	0.8252	0.1379	0.00859	16.97	1.057
1750	0.8181	0.1172	0.00880	14.42	1.083
2000	0.8137	0.1020	0.00900	12.55	1.108
2250	0.8117	0.09014	0.00910	11.13	1.120
2500	0.8113	0.08136	0.00905	10.01	1.114
2750	0.8125	0.07407	0.00880	9.115	1.083
3000	0.8157	0.6817	0.00835	8.389	1.028
3250	0.8217	0.06339	0.00738	7.801	0.9082
3500	0.8296	0.05943	0.00563	7.314	0.6928
3750	0.8404	0.05619	0.00265	6.915	0.3261
4000	0.8540	0.05353		6.588	
4250	0.8703	0.05134		6.318	
250°F					
		(3655)			
R.D.P.	0.8750	0.06556	0	8.068	0
600	0.902	0.412		50.70	
800	0.889	0.304	0.00625	37.41	0.7691
1000	0.8782	0.2405	0.00640	29.60	0.7876
1250	0.8668	0.1899	0.00655	23.370	0.8061
1500	0.8584	0.1567	0.00668	19.28	0.8221
1750	0.8522	0.1334	0.00680	16.42	0.8368
2000	0.8490	0.1163	0.00680	14.31	0.8368
2250	0.8471	0.1031	0.00670	12.69	0.8245
2500	0.8482	0.09292	0.00650	11.44	0.7999
2750	0.8508	0.08473	0.00625	10.43	0.7691
3000	0.8544	0.07800	0.00570	9.599	0.7162
3250	0.8610	0.07255	0.00460	8.928	0.5661
3500	0.8690	0.06800	0.00250	8.928	0.3077
3750	0.8793	0.06421		7.902	
4000	0.8913	0.06103		7.511	
4250	0.9081	0.05852		7.202	

[a] Figures in parentheses represent retrograde dew-point pressures in pounds per square inch absolute.

TABLE 8—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.83510 Gas-oil Ratio = 28,350 Cu Ft per Bbl					
100°F					
R.D.P.	0.7965	(3600) 0.06103	0	18.42	0
200	0.965	1.331		401.7	
400	0.930	0.641		193.5	
600	0.898	0.413		124.6	
800	0.868	0.299		90.24	
1000	0.840	0.232		70.02	
1250	0.8103	0.1788		53.96	
1500	0.7867	0.1447	0.003758	43.67	1.080
1750	0.7697	0.1213	0.003434	36.61	0.9687
2000	0.7566	0 1044	0.003090	31.51	0.8541
2250	0.7494	0.09187	0.002715	27.73	0.7334
2500	0.7472	0.08244	0.002300	24.88	0.6096
2750	0.7504	0.07527	0.001840	22.72	0.4798
3000	0.7588	0.06977	0.001310	21 06	0.3410
3250	0.7715	0.06548	0.000730	19.76	0.2022
3500	0.7885	0.06214	0.000122	18.75	0.05734
3750	0.8092	0.05952		17.96	
4000	0.8327	0.05743		17.33	
4250	0.8581	0.05593		16.88	
4500	0.8860	0.05431		16.39	
190°F					
R.D.P.	0.8730	(3288) 0.08502	0	25.66	0
200	0.973	1.558		470.2	
400	0.950	0.760		229.4	
600	0.930	0.496		149.7	
800	0.913	0.365		110.2	
1000	0.898	0.288		86.92	
1250	0.884	0.226		68.21	
1500	0.8728	0.1863	0.00170	56.22	0.5130
1750	0.8643	0.1581	0.00155	47.71	0 4678
2000	0.8585	0.1375	0.00137	41.50	0.4135
2250	0.8552	0.1217	0.00117	36.73	0.3531
2500	0.8550	0.1095	0.00093	33.05	0.2807
2750	0.8580	0.09990	0.00066	30.15	0.1992
3000	0.8538	0.09220	0.00036	27.83	0.1086
3250	0.8715	0.08586	0.00005	25.91	0.01509
3500	0.8819	0.08068		24.35	
3750	0.8945	0.07638		23.05	
4000	0.9082	0.07270		21.94	
4250	0.9230	0.06954		20.99	
4500	0.9385	0.06678		20 15	
250°F					
200	0.976	1.707		515.2	
400	0.955	0.835		252.0	
600	0.937	0.546		164.8	
800	0.923	0.404		121.9	
1000	0.912	0.319		96.27	
1250	0.902	0.252		76.05	
1500	0.895	0.209		63.07	
1750	0.8913	0.1781		53.75	
2000	0.8900	0.1556		46.96	
2250	0.8908	0.1385		41.80	
2500	0.8935	0.1250		37.72	
2750	0.8983	0.1143		34.50	
3000	0.9050	0.1055		31.84	
3250	0.9135	0.09831		29.67	
3500	0.9235	0.09229		27.85	
3750	0.9350	0.08721		26.32	
4000	0.9473	0.08283		25.00	
4250	0.9600	0.07901		23.85	
4500	0.9729	0.07562		22.82	

TABLE 8—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.9019 Gas-oil Ratio = 51,331 Cu Ft per Bbl					
100°F					
R.D.P.	0.7740	(3010) 0.07523	0	38.17	0
200	0.970	1.419		720.0	
400	0.941	0.688		349.1	
600	0.912	0.445		225.8	
800	0.883	0.323		163.9	
1000	0.856	0.250		126.9	
1250	0.827	0.194	0.00241	98.44	1.223
1500	0.8016	0.1563	0.00221	79.31	1.121
1750	0.7821	0.1307	0.00197	66.32	0.9996
2000	0.7681	0.1124	0.00168	57.03	0.6748
2250	0.7606	0.09889	0.00133	50.18	0.4617
2500	0.7589	0.08880	0.00091	45.06	0.2334
2750	0.7637	0.08124	0.00046	41.22	0.01015
3000	0.7739	0.07547	0.00002	38.29	
3250	0.7879	0.07092		35.99	
3500	0.8054	0.06731		34.15	
3750	0.8255	0.06440		32.68	
4000	0.8464	0.06190		31.41	
4250	0.8683	0.05976		30.32	
4500	0.8905	0.05789		29.37	
4750	0.9134	0.05625		28.54	
5000	0.9363	0.05478		27.80	
190°F					
R.D.P.	0.8780	(2960) 0.1007	0	51.095	0
200	0.980	1.664		844.3	
400	0.961	0.816		414.0	
600	0.944	0.534		271.0	
800	0.929	0.394		199.9	
1000	0.915	0.311		157.8	
1250	0.900	0.245		124.3	
1500	0.8882	0.2011	0.00114	102.0	0.5835
1750	0.8796	0.1707	0.00099	86.61	0.4973
2000	0.8740	0.1484	0.00082	75.30	0.4059
2250	0.8714	0.1315	0.00062	66.72	0.3095
2500	0.8714	0.1184	0.00038	60.08	0.2080
2750	0.8737	0.1079	0.00009	54.75	0.09641
3000	0.8737	0.09950		50.49	
3250	0.8870	0.09268		47.03	
3500	0.8973	0.08706		44.18	
3750	0.9097	0.08237		41.80	
4000	0.9235	0.07840		39.78	
4250	0.9382	0.07496		38.04	
4500	0.9547	0.07204		36.55	
4750	0.9727	0.06954		35.29	
5000	0.9909	0.06730		34.15	
250°F					
R.D.P.	0	0			
200	0.985	1.83		928.6	
400	0.972	0.901		457.2	
600	0.959	0.593		300.9	
800	0.947	0.439		222.8	
1000	0.936	0.347		176.1	
1250	0.925	0.274		139.0	
1500	0.916	0.227		115.2	
1750	0.9106	0.1930		97.93	
2000	0.9070	0.1682		85.35	
2250	0.9060	0.1494		75.81	
2500	0.9079	0.1347		68.35	
2750	0.9124	0.1231		62.46	
3000	0.9190	0.1136		57.64	
3250	0.9275	0.1059		53.73	
3500	0.9371	0.09932		50.40	
3750	0.9484	0.09377		47.58	
4000	0.9613	0.08915		45.24	
4250	0.9763	0.08521		43.24	
4500	0.9930	0.08186		41.54	
4750	1.0114	0.07895		40.06	
5000	1.0287	0.07632		38.73	

TABLE 8—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.9662 Gas-oil Ratio = 159,160 Cu Ft per Bbl					
100°F					
200	0.973	1.501		2,210.0	
400	0.945	0.729		1,073.4	
600	0.917	0.472		695.0	
800	0.890	0.343		505.0	
1000	0.864	0.267		393.1	
1250	0.8350	0.2062		303.6	
1500	0.8120	0.1671		246.0	
1750	0.7945	0.1401		206.3	
2000	0.7820	0.1207		177.7	
2250	0.7738	0.1061		156.2	
2500	0.7729	0.09542		140.5	
2750	0.7780	0.08731		128.6	
3000	0.7887	0.08113		119.5	
3250	0.8024	0.07619		112.2	
3500	0.8197	0.07227		106.4	
3750	0.8379	0.06896		101.5	
4000	0.8575	0.06616		97.41	
4250	0.8782	0.06377		93.89	
4500	0.8997	0.06170		90.85	
190°F					
200	0.984	1.763		2,595.8	
400	0.968	0.867		1,276.5	
600	0.953	0.569		837.8	
800	0.939	0.420		618.4	
1000	0.926	0.332		488.8	
1250	0.9118	0.2613		384.7	
1500	0.9005	0.2151		316.7	
1750	0.8915	0.1825		268.7	
2000	0.8860	0.1587		233.7	
2250	0.8830	0.1406		207.0	
2500	0.8822	0.1264		186.1	
2750	0.8850	0.1153		169.8	
3000	0.8903	0.1063		156.5	
3250	0.8975	0.09893		145.7	
3500	0.9075	0.09288		136.8	
3750	0.9187	0.08776		129.2	
4000	0.9315	0.08342		122.8	
4250	0.9445	0.07961		117.2	
4500	0.9585	0.07630		112.3	
250°F					
200	0.986	1.9292		2,840.5	
400	0.974	0.8723		1,284.4	
600	0.964	0.6287		925.7	
800	0.954	0.4666		687.0	
1000	0.9463	0.3703		545.2	
1250	0.9382	0.2937		432.4	
1500	0.9328	0.2434		358.4	
1750	0.9273	0.2074		305.4	
2000	0.9245	0.1809		266.4	
2250	0.9240	0.1607		236.6	
2500	0.9253	0.1448		213.2	
2750	0.9285	0.1321		194.5	
3000	0.9342	0.1219		179.5	
3250	0.9412	0.1133		166.8	
3500	0.9503	0.1063		156.5	
3750	0.9600	0.1002		147.5	
4000	0.9705	0.09494		139.8	
4250	0.9815	0.09037		133.1	
4500	0.9928	0.08633		127.1	

TABLE 9—*Volumetric Behavior of Experimentally Studied Mixtures for System C*

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.7755 Gas-oil Ratio = 22,356 Cu Ft per Bbl					
40°F					
R.D.P.	0.6475	(2820)[a] 0.05036	0	13.587	0
200	0.9175	1.0062		271.5	
400	0.8563	0.4695		126.68	
600	0.8102	0.2962	0.00663	79.91	1.789
800	0.7715	0.21152	0.00703	57.07	1.897
1000	0.7360	0.16143	0.00739	43.55	1.994
1250	0.6959	0.12211	0.00775	32.94	2.091
1500	0.6619	0.09678	0.00796	26.11	2.148
1750	0.6374	0.07989	0.00786	21.554	2.121
2000	0.6221	0.06822	0.00708	18.407	1.910
2250	0.6179	0.06023	0.00557	16.251	1.503
2500	0.6245	0.05479	0.00336	14.782	0.906
2750	0.6412	0.05114	0.00075	13.798	0.202
3000	0.6667	0.04874		13.151	
3250	0.6988	0.04716		12.724	
3500	0.7345	0.04603		12.418	
3750	0.7714	0.04512		12.173	
4000	0.8076	0.04428		11.948	
100°F					
R.D.P.	0.7380	(3080) 0.05886	0	15.882	0
200	0.9395	1.1540		311.3	
400	0.8973	0.5511		148.68	
600	0.8655	0.3544	0.00495	95.61	1.336
800	0.8386	0.2575	0.00535	69.48	1.443
1000	0.8138	0.19992	0.00565	53.94	1.524
1250	0.7859	0.15446	0.00591	41.67	1.594
1500	0.7625	0.12488	0.00597	33.69	1.611
1750	0.7437	0.10440	0.00584	28.17	1.576
2000	0.7302	0.08969	0.00544	24.199	1.468
2250	0.7223	0.07886	0.00481	21.278	1.298
2500	0.7200	0.07075	0.00377	19.089	1.017
2750	0.7234	0.06462	0.00225	17.436	0.607
3000	0.7335	0.06007	0.00055	16.206	0.148
3250	0.7503	0.05672		15.302	
3500	0.7729	0.05425		14.637	
3750	0.7995	0.05238		14.131	
4000	0.8290	0.05092		13.737	
160°F					
R.D.P.	0.8020	(3090) 0.07060	0	19.047	0
200	0.9578	1.3026		351.4	
400	0.9254	0.6293		169.78	
600	0.9002	0.4081	0.00332	110.10	0.896
800	0.8800	0.2992	0.00365	80.72	0.985
1000	0.8622	0.23452	0.00389	63.27	1.050
1250	0.8432	0.18348	0.00401	49.50	1.082
1500	0.8269	0.14995	0.00402	40.46	1.085
1750	0.8130	0.12637	0.00386	34.10	1.041
2000	0.8023	0.10911	0.00352	29.44	0.950
2250	0.7952	0.09613	0.00302	25.94	0.815
2500	0.7922	0.08619	0.00234	23.255	0.631
2750	0.7934	0.07848	0.00145	21.173	0.391
3000	0.7989	0.07244	0.00041	19.543	0.1106
3250	0.8089	0.06770		18.265	
3500	0.8230	0.06396		17.256	
3750	0.8408	0.06099		16.454	
4000	0.8615	0.05858		15.806	

TABLE 9—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
220°F					
R.D.P.	0.8545	(2795) 0.09121	0	24.608	0
200	0.9717	1.4495		391.1	
400	0.9490	0.7078		190.97	
600	0.9307	0.4628	0.00157	124.86	0.424
800	0.9155	0.3414	0.00183	92.11	0.494
1000	0.9023	0.2692	0.00201	72.63	0.542
1250	0.8878	0.21189	0.00208	57.17	0.561
1500	0.8754	0.17411	0.00201	46.98	0.542
1750	0.8651	0.14748	0.00184	39.79	0.496
2000	0.8578	0.12796	0.00157	34.52	0.424
2250	0.8530	0.11310	0.00117	30.51	0.316
2500	0.8520	0.10167	0.00069	27.43	0.186
2750	0.8539	0.09264	0.00011	24.993	0.030
3000	0.8592	0.08544		23.053	
3250	0.8677	0.07965		21.490	
3500	0.8789	0.07492		20.213	
3750	0.8922	0.07098		19.151	
4000	0.9074	0.06768		18.260	

Weight Fraction Trap Gas = 0.7924
Gas-oil Ratio = 24,661 Cu Ft per Bbl

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
40°F					
R.D.P.	0.6555	(2810) 0.05198	0	15.169	0
200	0.9235	1.0288		300.3	
400	0.8615	0.4799		140.05	
600	0.8148	0.3026	0.00642	88.30	1.874
800	0.7771	0.2164	0.00692	63.16	2.020
1000	0.7433	0.1656	0.00731	48.33	2.134
1250	0.7038	0.1254	0.00765	36.61	2.233
1500	0.6688	0.09934	0.00780	28.99	2.277
1750	0.6414	0.08166	0.00757	23.833	2.210
2000	0.6260	0.06974	0.00679	29.353	1.982
2250	0.6231	0.06170	0.00529	18.007	1.544
2500	0.6316	0.05629	0.00309	16.428	0.902
2750	0.6497	0.05264	0.00062	15.362	0.181
3000	0.6760	0.05021		15.652	
3250	0.7086	0.04858		14.177	
3500	0.7438	0.04735		13.819	
3750	0.7783	0.04624		13.496	
4000	0.8130	0.04528		13.216	
100°F					
R.D.P.	0.7481	(3065) 0.06091	0	17.777	0
200	0.9488	1.1839		345 5	
400	0.9055	0.5649		164.87	
600	0.8707	0.3622	0.00475	105.69	1.386
800	0.8423	0.2628	0.00508	76.68	1.483
1000	0.8179	0.20412	0.00538	59.57	1.570
1250	0.7910	0.15792	0.00565	46.09	1.649
1500	0.7693	0.12799	0.00573	37.35	1.672
1750	0.7522	0.10727	0.00553	31.31	1.614
2000	0.7403	0.09238	0.00511	26.96	1.492
2250	0.7331	0.08131	0.00445	23.730	1.299
2500	0.7312	0.07299	0.00348	21.302	1.016
2750	0.7349	0.06669	0.00213	19.464	0.622
3000	0.7444	0.06192	0.00046	18.072	0.134
3250	0.7609	0.05843		17.052	
3500	0.7835	0.05587		16.304	
3750	0.8099	0.05390		15.730	
4000	0.8370	0.05222		15.240	

TABLE 9—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
160°F					
R.D.P.	0.8128	(3075) 0.07304	0	21.318	0
200	0.9663	1.3350		389.7	
400	0.9359	0.6465		188.70	
600	0.9096	0.4189	0.00313	122.27	0.914
800	0.8874	0.3065	0.00344	89.46	1.004
1000	0.8685	0.23998	0.00364	70.05	1.062
1250	0.8488	0.18763	0.00375	54.77	1.095
1500	0.8327	0.15339	0.00372	44.77	1.086
1750	0.8200	0.12947	0.00354	37.78	1.033
2000	0.8107	0.11200	0.00320	32.69	0.934
2250	0.8050	0.09886	0.00269	28.86	0.785
2500	0.8030	0.08875	0.00203	25.90	0.593
2750	0.8044	0.08082	0.00120	23.591	0.350
3000	0.8100	0.07460	0.00029	21.776	0.085
3250	0.8208	0.06978		20.369	
3500	0.8364	0.06603		19.273	
3750	0.8552	0.06301		18.393	
4000	0.8763	0.06053		17.669	
220°F					
R.D.P.	0.8648	(2780) 0.09428	0	27.52	0
200	0.9783	1.4824		432.7	
400	0.9576	0.7255		211.77	
600	0.9385	0.4740	0.00143	138.37	0.417
800	0.9217	0.3492	0.00171	101.92	0.499
1000	0.9075	0.2750	0.00184	80.28	0.537
1250	0.8929	0.21649	0.00187	63.19	0.546
1500	0.8819	0.17818	0.00179	52.01	0.522
1750	0.8735	0.15127	0.00160	44.15	0.467
2000	0.8678	0.13150	0.00132	38.38	0.385
2250	0.8640	0.11638	0.00096	33.97	0.280
2500	0.8625	0.10456	0.00054	30.52	0.158
2750	0.8461	0.09523	0.00007	27.80	0.020
3000	0.8700	0.08789		25.65	
3250	0.8803	0.08209		23.960	
3500	0.8937	0.07739		22.588	
3750	0.9091	0.07347		21.445	
4000	0.9258	0.07014		20.474	

[a] Figures in parentheses represent retrograde dew-point pressures expressed in pounds per square inch absolute.

TABLE 10—*Volumetric Behavior of Experimentally Studied Mixtures for System D*

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.5938 Gas-oil Ratio = 9091 Cu Ft per Bbl					
100°F					
R.D.P.	(4060)[a] 0.8340	0.04192	0	5.787	0
600	0.8093	0.2753	10.04	38.00	1.386
800	0.7824	0.19958	10.60	27.55	1.463
1000	0.7595	0.15499	11.12	21.397	1.535
1250	0.7355	0.12007	11.67	16.576	1.611
1500	0.7155	0.09734	12.13	13.438	1.675
1750	0.7009	0.08173	12.44	11.283	1.717
2000	0.6920	0.07061	12.52	9.748	1.728
2250	0.6890	0.06249	12.46	8.627	1.720
2500	0.6926	0.05653	12.11	7.805	1.672
2750	0.7024	0.05212	11.26	7.196	1.555
3000	0.7180	0.04884	9.80	6.743	1.353
3250	0.7395	0.04643	7.84	6.410	1.082
3500	0.7651	0.04461	5.28	6.158	0.729
3750	0.7940	0.04321	2.30	5.965	0.318
4000	0.8261	0.04215	0.36	5.818	0.050
4250	0.8603	0.04131		5.703	
4500	0.8957	0.04062		5.608	
4750	0.9310	0.04000		5.522	
5000	0.9664	0.03944		5.445	
5500	1.0378	0.03851		5.316	
190°F					
R.D.P.	(4388) 0.9000	0.04859	0	6.707	0
600	0.8745	0.3453	7.53	47.66	1.040
800	0.8545	0.2530	8.02	34.93	1.107
1000	0.8379	0.19848	8.46	27.40	1.168
1250	0.8213	0.15564	8.89	21.487	1.227
1500	0.8083	0.12765	9.18	17.622	1.267
1750	0.7991	0.10817	9.34	14.933	1.289
2000	0.7932	0.09395	9.36	12.970	1.292
2250	0.7904	0.08321	9.23	11.488	1.274
2500	0.7905	0.07490	8.94	10.340	1.234
2750	0.7937	0.06837	8.44	9.438	1.165
3000	0.7999	0.06316	7.66	8.720	1.058
3250	0.8100	0.05904	6.57	8.151	0.907
3500	0.8242	0.05578	5.15	7.701	0.711
3750	0.8419	0.05318	3.43	7.342	0.474
4000	0.8628	0.05110	1.58	7.054	0.218
4250	0.8863	0.04940	0.35	6.820	0.048
4500	0.9121	0.04801		6.629	
4750	0.9400	0.04688		6.472	
5000	0.9693	0.04592		6.340	
5500	1.0303	0.04438		6.126	
250°F					
R.D.P.	(4420) 0.9330	0.05462	0	7.541	0
600	0.9092	0.3921	5.79	54.13	0.799
800	0.8930	0.2888	6.20	39.88	0.856
1000	0.8801	0.22773	6.56	31.44	0.906
1250	0.8676	0.17960	6.91	24.794	0.954
1500	0.8571	0.14785	7.11	20.411	0.982
1750	0.8492	0.12556	7.20	17.334	0.994
2000	0.8438	0.10917	7.15	15.071	0.987
2250	0.8411	0.09673	6.98	13.354	0.964
2500	0.8411	0.08706	6.65	12.018	0.918
2750	0.8439	0.07941	6.15	10.962	0.849
3000	0.8489	0.07322	5.45	10.108	0.752
3250	0.8569	0.06822	4.54	9.419	0.627
3500	0.8680	0.06417	3.46	8.859	0.478
3750	0.8819	0.06085	2.28	8.401	0.315
4000	0.8988	0.05814	1.14	8.027	0.157
4250	0.9180	0.05589	0.32	7.716	0.042
4500	0.9400	0.05405		7.463	
4750	0.9631	0.05247		7.243	
5000	0.9871	0.05108		7.052	
5500	1.0362	0.04875		6.730	

TABLE 10—(*Continued*)

Pressure, Psia	Compressibility Factor	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
Weight Fraction Trap Gas = 0.6454 Gas-oil Ratio = 11,226 Cu Ft per Bbl					
100°F					
R.D.P.	(4344) 0.8610	0.04290	0	6.786	0
600	0.8160	0.2944	9.19	46.56	1.454
800	0.7893	0.21357	9.70	33.78	1.534
1000	0.7655	0.16570	10.15	26.21	1.605
1250	0.7395	0.12806	10.63	20.255	1.681
1500	0.7180	0.10361	10.97	16.388	1.735
1750	0.7025	0.08689	11.17	13.744	1.767
2000	0.6944	0.07516	11.15	11.887	1.764
2250	0.6918	0.06656	10.92	10.527	1.727
2500	0.6940	0.06009	10.39	9.504	1.643
2750	0.7017	0.05523	9.42	8.736	1.490
3000	0.7150	0.05159	7.99	8.160	1.264
3250	0.7343	0.04891	6.15	7.736	0.973
3500	0.7584	0.04690	4.11	7.419	0.650
3750	0.7866	0.04541	2.22	7.182	0.351
4000	0.8172	0.04422	0.93	6.995	0.147
4250	0.8487	0.04323	0.19	6.837	0.030
4500	0.8813	0.04239		6.705	
4750	0.9140	0.04165		6.588	
5000	0.9471	0.04100		6.485	
5500	1.0141	0.03991		6.313	
190°F					
R.D.P.	(4077) 0.9210	0.04948	0	7.826	0
600	0.8794	0.3683	6.70	58.25	1.060
800	0.8592	0.2699	7.15	42.69	1.131
1000	0.8429	0.21180	7.51	33.50	1.188
1250	0.8259	0.16602	7.82	26.26	1.237
1500	0.8124	0.13609	8.01	21.525	1.267
1750	0.8020	0.11515	8.08	18.213	1.278
2000	0.7951	0.09989	8.03	15.800	1.270
2250	0.7916	0.08840	7.86	13.983	1.243
2500	0.7911	0.07951	7.53	12.576	1.191
2750	0.7938	0.07253	7.01	11.472	1.109
3000	0.8000	0.06701	6.23	10.598	0.985
3250	0.8101	0.06263	5.24	9.907	0.829
3500	0.8243	0.05918	4.03	9.360	0.637
3750	0.8417	0.05640	2.73	8.921	0.432
4000	0.8607	0.05407	1.55	8.552	0.245
4250	0.8814	0.05211	0.65	8.242	0.103
4500	0.9038	0.05047	0.18	7.982	0.028
4750	0.9282	0.04910		7.766	
5000	0.9540	0.04794		7.583	
5500	1.0078	0.04604		7.283	
250°F					
R.D.P.	(4705) 0.9520	0.05554	0	8.784	0
600	0.9116	0.4170	4.99	65.96	0.789
800	0.8960	0.3074	5.33	48.62	0.843
1000	0.8834	0.24247	5.62	38.35	0.889
1250	0.8704	0.19112	5.87	30.23	0.929
1500	0.8598	0.15733	6.02	24.885	0.952
1750	0.8517	0.13358	6.05	21.128	0.957
2000	0.8467	0.11620	6.00	18.379	0.949
2250	0.8442	0.10298	5.79	16.288	0.916
2500	0.8446	0.09273	5.41	14.667	0.856
2750	0.8473	0.08457	4.88	13.376	0.772
3000	0.8528	0.07802	4.25	12.341	0.672
3250	0.8605	0.07267	3.51	11.494	0.555
3500	0.8708	0.06829	2.66	10.801	0.421
3750	0.8834	0.06466	1.78	10.227	0.282
4000	0.8985	0.06165	1.05	9.752	0.166
4250	0.9160	0.05916	0.53	9.357	0.084
4500	0.9353	0.05705	0.18	9.023	0.028
4750	0.9558	0.05523		8.736	
5000	0.9775	0.05366		8.487	
5500	1.0235	0.05108		8.079	

[a] Figures in parentheses represent retrograde dew-point pressures in pounds per square inch absolute.

TABLE 11—*Retrograde Dew-point Pressure*

Tank-oil Gravity, Deg API	Gas-oil Ratio, Cu Ft per Bbl					
	15,000	20,000	25,000	30,000	35,000	40,000
			100°F			
52	4,440[a]	4,140	3,880	3,680	3,530	3,420
54	4,190	3,920	3,710	3,540	3,410	3,310
56	3,970	3,730	3,540	3,390	3,280	3,180
58	3,720	3,540	3,380	3,250	3,140	3,060
60	3,460	3,340	3,220	3,100	3,010	2,930
62	3,290	3,190	3,070	2,970	2,880	2,800
64	3,080	3,010	2,920	2,840	2,770	2,700
			160°F			
52	4,760	4,530	4,270	4,060	3,890	3,650
54	4,400	4,170	3,950	3,760	3,610	3,490
56	4,090	3,890	3,690	3,520	3,380	3,270
58	3,840	3,650	3,470	3,320	3,200	3,110
60	3,610	3,430	3,280	3,150	3,040	2,960
62	3,390	3,240	3,100	2,990	2,890	2,810
64	3,190	3,060	2,930	2,820	2,740	2,670
			220°F			
54	4,410	4,230	4,050	3,890	3,750	3,620
56	3,990	3,780	3,600	3,440	3,300	3,180
58	3,700	3,480	3,280	3,110	2,970	2,850
60	3,430	3,210	3,030	2,880	2,760	2,660
62	3,150	2,970	2,800	2,670	2,570	2,480
64	2,900	2,740	2,590	2,470	2,380	2,300

[a] Pressure expressed in pounds per square inch absolute.

TABLE 12—*Values of Coefficient A*[a]

$A \times 10^3$

Pressure, Psia	100°F	130°F	160°F	190°F	220°F	250°F
600	4.58	4.67	4.75	4.83	4.89	4.93
800	4.46	4.57	4.67	4.76	4.83	4.87
1000	4.35	4.47	4.59	4.69	4.77	4.82
1250	4.21	4.35	4.49	4.62	4.71	4.77
1500	4.09	4.25	4.41	4.55	4.66	4.73
1750	3.99	4.17	4.34	4.50	4.62	4.71
2000	3.93	4.11	4.29	4.46	4.59	4.69
2250	3.89	4.08	4.26	4.43	4.57	4.68
2500	3.88	4.06	4.25	4.42	4.57	4.68
2750	3.89	4.07	4.26	4.44	4.58	4.69
3000	3.92	4.10	4.29	4.47	4.61	4.71

[a] Coefficient of equation 1.

TABLE 13—*Comparison of Calculated and Observed Values of Formation Volume*

Pressure, Psia	Calculated[a]	Observed	Difference, Pct	Calculated	Observed	Difference, Pct	Calculated	Observed	Difference, Pct
				100°F					
	Gas-oil Ratio 9091 Cu Ft per Bbl			Gas-oil Ratio 25,161 Cu Ft per Bbl			Gas-oil Ratio 51,331 Cu Ft per Bbl		
1,000	22.09	21.397	+3.2	61.14	61.48	−0.6	124.7	126.9	−1.7
2,000	10.00	9.748	+2.6	27.68	27.48	+0.7	56.46	57.03	−1.0
3,000	6.64	6.743	−1.5	18.37	18.48	−0.6	37.47	38.29	−2.1
				160°F					
	Gas-oil Ratio 19,410 Cu Ft per Bbl			Gas-oil Ratio 24,661 Cu Ft per Bbl					
1,000	55.12	55.73	−1.1	70.04	70.05	0.0			
2,000	25.82	25.91	−0.3	32.80	32.69	+0.3			
3,000	17.27	17.205	+0.4	21.95	21.776	+0.8			
				250°F					
	Gas-oil Ratio 9091 Cu Ft per Bbl			Gas-oil Ratio 28,350 Cu Ft per Bbl			Gas-oil Ratio 51,331 Cu Ft per Bbl		
1,000	31.18	31.44	−0.8	97.24	96.27	+1.0	176.1	176.1	0.0
2,000	15.09	15.071	+0.1	47.06	46.96	+0.2	85.21	85.35	−0.2
3,000	10.18	10.108	+0.7	31.75	31.84	−0.3	57.49	57.64	−0.3

[a] Calculated from Eq 1 employing values of the coefficient *A* from Table 12.

Plastic Used to Consolidate Incompetent Formations

By P. H. Cardwell*

(Galveston Meeting, October 1946)

ABSTRACT

The effect of various plastics upon the permeability of a sand and the mechanism of their ensuring permeability within the consolidated sand body is discussed. Data are presented on various properties of the plastic materials used in sand consolidation and the effect of temperature and usable temperature ranges are considered.

The recovery of petroleum from unconsolidated sands presents serious production problems, owing to sloughing of the formation. The solution of some of these problems usually has been by mechanical methods.[1] The ideal way of controlling the sloughing tendencies of these unconsolidated formations, however, is to prevent the movement of the individual sand grains by the use of a bonding medium.

A step in the desired direction was taken by Irons and Stoesser[2] when they taught the use of liquid plastics to produce a consolidating deposit that prevents sloughing. More recently, Wrightsman and Buckley[3] proposed a modification of this process. In this use of the liquid plastic, the sand grains become coated and the ensuing hardening of the plastic by polymerization or condensation cements together the sand particles. Liquid plastics that have been suggested for this purpose are of the following types: phenolformaldehyde, alkyd resins, vinyl type resins, polystyrene and the acrylic esters.

When the flow of fluids through a sand must not be materially reduced, it is essential only to cement together the sand grains with liquid plastic and leave a portion of the interstitial space for fluid flow. To be assured of obtaining fluid flow through the sand interstices after injection of plastic, it has been necessary in the past to remove the excess plastic from the interstices between the particles before it sets.

Wrightsman and Buckley suggest two methods for the removal of the excess plastic from the interstices of the sand: (1) to flush the excess plastic back into the formation, away from the well bore, by use of oil or water; (2) to produce the well before the plastic has set, thereby moving the excess plastic into the well bore. Under certain well conditions it is very difficult to remove the excess plastic from all parts of the formation by either of these methods and leave the formation consolidated with no sections completely sealed.

The method* described herein of retaining permeability within a sand body is to use a liquid plastic that upon setting ensures permeability within the consolidated sand body. This cements the sand grains but obviates the need for removing plastic from the interstices of the sand. One of the ways of accomplishing this is to use a liquid plastic that occupies a considerably greater volume than the solidified resin it yields on further polymerization or condensation in situ. In order to be satisfactory, the volume of the plastic while liquid should be at least one and one half times the volume of the solid formed. Preferably,

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* Dowell Incorporated, Tulsa, Oklahoma.

[1] References are at the end of the paper.

* Patent pending.

the liquid volume should be two to three times the solid volume.

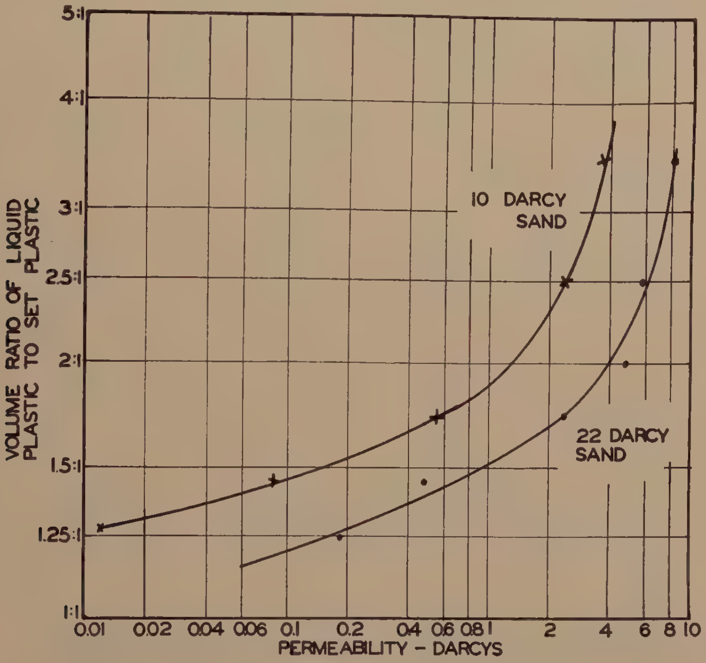

FIG 1—EFFECT OF VARIOUS PLASTICS ON PERMEABILITY

When a sand is consolidated with plastic there is a decrease in its permeability because the plastic forms a thin film over the sand particles, which reduces somewhat the size of the interstices between the grains of sand. However, it is possible to control the decrease in permeability by adjusting the relationship between the liquid volume of the plastic and the volume of the solid plastic obtained by means of polymerization or condensation in situ. As the volume of the set solid plastic approaches that of the liquid, the more plastic there is bonded to the sand particles the greater is the decrease in permeability. When the volume of solid plastic for all practical purposes is the same as that of the liquid from which it was formed, there is usually sufficient set plastic within the sand to seal completely the formation. In this case the plastic is similar to the materials used for shutting off unwanted fluids, such as water or gas[2,4,5] in producing wells.

The relationship between the liquid volume and the solid volume of the set plastic can be controlled by changes made in the manufacture of the liquid plastic. Control of the permeability when consolidating sand with plastic is illustrated by the graph in Fig 1, which shows the effect on the permeability of sand when the ratio of the liquid volume to that of the solid volume of the plastic varies. In the tests from which these data were obtained, two unconsolidated sands having original permeabilities of 10 and 22 darcys were completely saturated with different liquid plastics. After the plastics had set, the permeabilities of the consolidated sands were determined.

In the development of the liquid plastics satisfactory for use to consolidate incompetent formations, the laboratory work as well as the experience gained from carrying on some 150 actual field treatments[1] has shown that the most successful plastics are those having a liquid volume 1.4 to 2.5 times greater than the volume of the solid formed from the liquid. The physical properties of the liquid plastics now being used for sand consolidation are given in Table 1.

TABLE 1—*Physical Properties of Sand Consolidation Plastics*

Plastic	Viscosity Centipoises 80°F	Specific Gravity 80°F	Ratio of Liquid Volume to Volume of Set Solid
No. 1..........	1.3	0.99	2.5:1
No. 3..........	1.2	0.99	2.5:1
No. 4..........	1.9	1.05	1.7:1

Since the plastics through polymerization or condensation form solids that are considerably denser than the liquids from which they are formed, there is always a 40 to 70 pct decrease in volume as they set. As a consequence of this decrease in volume, which leaves the sand permeable, it is impossible for the plastic to plug a formation. This has been borne out by the fact that in the course of some 150 actual field treatments by one service organization using this type of plastic there has been no indication of any plugging of the formation.

The plastics used for sand consolidation are of the thermosetting type. This means that they set as a result of heat, to infusible hard solids, which cannot be softened when subjected to additional heat. The heat used to set the plastics is the heat encountered in the well. The liquid plastics are fairly stable at ordinary temperatures, but when properly treated or subjected to the temperatures found in oil wells, their rate of polymerization or condensation is increased, causing the liquid to become a solid in a relatively short time. The time required for the liquid plastic to make the transition from a liquid to a solid state depends, among other factors, upon the nature of the plastic and the temperature to which it is subjected.

The temperature range at which a specific liquid plastic material can be used is rather limited because with some plastics an increase of 20°F usually will reduce the setting time about one half, and a decrease of 20°F will double the time required for the plastic to set or become a hard solid. Thus, the usable temperature range of many liquid plastics is about 60°F, because a liquid that requires 2 hr to set at a certain temperature will require some 16 hr to set at a temperature 60° lower. Means are available by which the usable temperature range of the liquid plastics can be increased. This can be accomplished by proper adjustment of the chemical composition of the plastic material or by the addition of a "catalyst," which is a material that is capable of increasing the rate of polymerization or condensation of a liquid plastic. Fig 2 illustrates the time required for the different plastics to set at various temperatures.

The plastics used for sand consolidation are inert and not affected in any way by water, oil or gas. The experience gained to date indicates that the plastic binding material is permanent.

TABLE 2—*Compressive and Tensile Strength of Plastic Consolidated Sand*

Plastic	Permeability of Unconsolidated Sand, Darcys	Compressive Strength, Lb per Sq In.	Tensile Strength, Lb per Sq In.
No. 3..........	10	2,050	230
No. 3..........	22	2,400	170

Table 2 gives the compressive and tensile strengths of sands that have been consolidated with plastic. The sands used to make these tests were ungraded materials having original permeabilities of 10 and

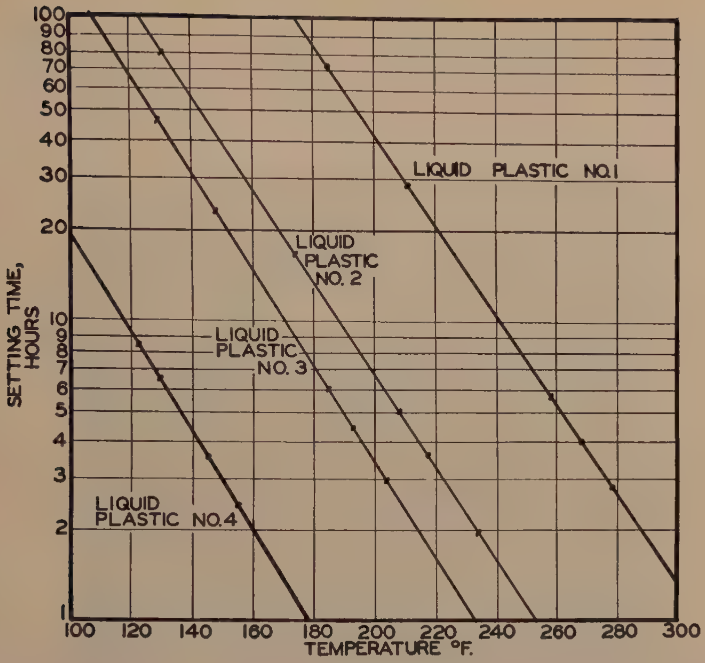

FIG 2—SETTING TIME AT VARIOUS TEMPERATURES OF SAND CONSOLIDATION PLASTICS.

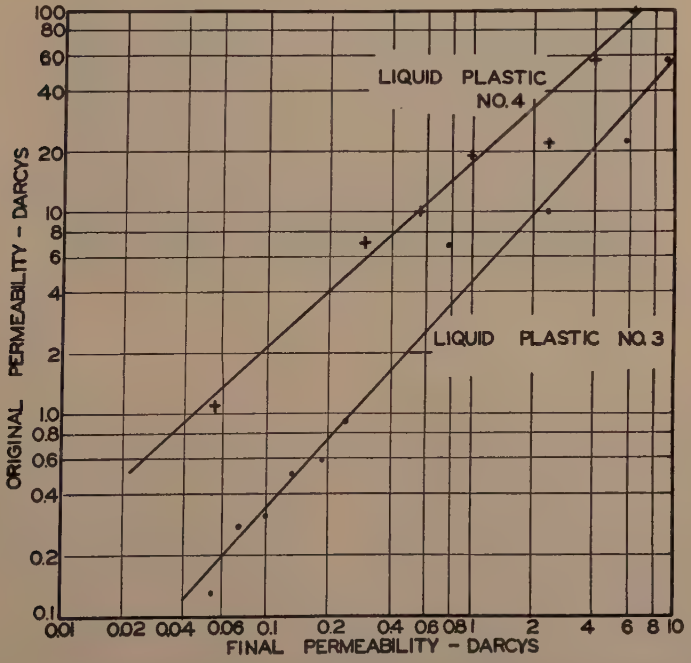

FIG 3—RELATIONSHIP OF PERMEABILITIES BEFORE AND AFTER CONSOLIDATION.

22 darcys, respectively. The compressive strengths of the plastic consolidated sands are about the same as that of the majority of the oil-well consolidated formation sands.[6]

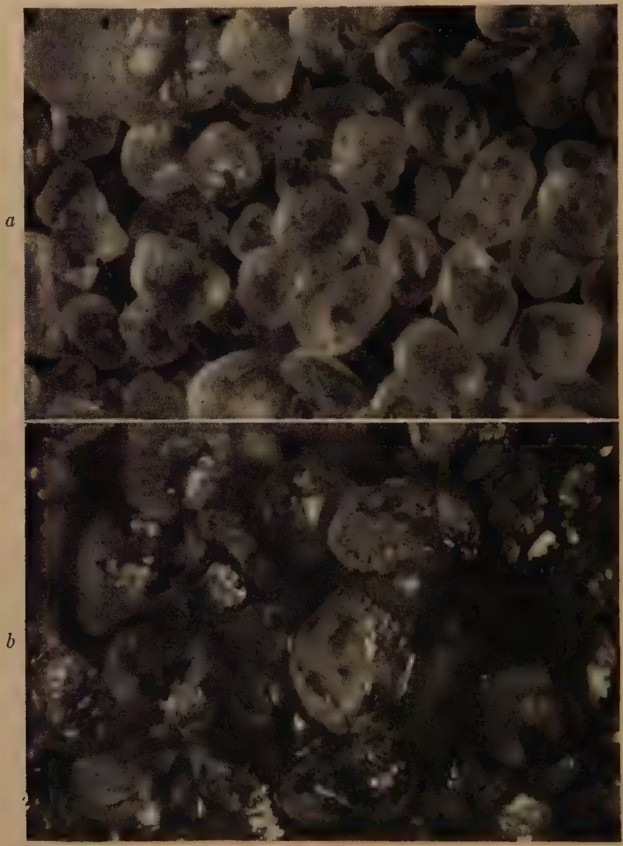

Fig 4—Unconsolidated sand. × 20
a. Original state.
b. After plastic consolidation

In order that the plastics in the liquid state may penetrate into the incompetent formations sufficiently, it is essential that they have low viscosities. Table 1 shows the plastics in use today have viscosities only slightly above that of water. Another property of these plastics that helps to bring about better penetration into formations, and displacement of water and oil that may be present, is their interfacial tension against crude oils and against formation waters. The interfacial tensions between the liquid plastics and oil-well brines are of the magnitude of approximately one dyne per centimeter, while between liquid plastics and crude oils the interfacial tensions are in the order of 2 to 3 dynes per centimeter.

As has been mentioned earlier, there is a decrease in the permeability of an incompetent formation when it is consolidated with plastic. However, since most of the producing unconsolidated sands have permeabilities as high as 2 darcys, a reduction of such a permeability by as much as 50 to 80 pct would be of no particular consequence. In Fig 3 is shown the effect of the various plastics in reducing the permeabilities of different sands. The data plotted in this graph were obtained by saturating sands of varying permeabilities with liquid plastics and measuring the resulting permeabilities after the plastics had set. A few of the results, especially those having original permeabilities below one darcy, were obtained by applying the sand consolidation plastics to sand cores. The higher the original permeability, the greater the percentage of reduction of the permeability.

When the sand consolidation plastic penetrates an incompetent sand, the plastic displace water and oil from the sand, but an excellent bond with the sand particles is not obtained unless the water and oil are displaced from the surface of the sand grains. The sand consolidation plastics used are so formulated as to preferentially wet and, therefore, bond to the sand grains. Since water as opposed to other liquids usually preferentially wets sand, the property of the liquid plastic to remove practically all of the water from the sand surface is very advantageous and the result of a combination of two factors: (1) the use of a wetting agent of the correct type in the plastic, and (2) the slight capacity of the plastic to dissolve water. These two factors have been taken into consideration in the development of the plastic formulations and, as a result, those currently used bond to sands in water-wet formations.

In the application of plastics for sand consolidation, the formation within a few inches of the borehole is completely saturated with the liquid plastic. As the liquid plastic undergoes the polymerization or condensation to a solid having a volume less than that of the original liquid, the plastic becomes bonded to the sand grains rather than merely solidifying within the interstices of the sand. This means that the adhesive forces between the plastic and sand are sufficiently strong to give the plastic a good bond to the sand and are somewhat greater than the cohesive forces between the molecules of the plastic, so that the plastic as it sets does not become a solid existing as a hard mass in the interstices between the sand grains without being bonded to the sand itself. The cohesive forces existing between molecules of the solid plastic are of sufficient magnitude to cement and hold together the sand particles, because, once the plastic has covered and bonded to the sand grains, the grains are held together only by the cohesive forces of the set plastic. The micrograph in Fig 4 illustrates how sand is consolidated by means of plastics. The fact that the individual grains are bonded together and good permeability still exists in the sand body clearly is seen in the view of the plastic consolidated sand.

It is believed that the results obtained from actual use of this material in wells points the way to a solution of a troublesome and expensive oil-production problem.

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Possibilities and Problems of Drilling beyond the Continental Shelves

By Henry Emmett Gross,* Member A.I.M.E.

(Chicago Meeting, February 1946)

Abstract

A plausible method of drilling beyond the continental shelves is set forth with limitations of the method. The continental shelves comprise the water-covered portions of land masses out to 600 ft. of water, or 100 fathoms. The problems and possibilities of drilling beyond this depth are discussed in this paper.

Introduction

Much attention is being given the problem of developing petroleum beneath the open sea. Geophysical surveys have been made 26 miles offshore[1] from the continental United States, and once offshore ownership is established it is likely that there will be drilling for oil on the continental shelves.

More than two years ago the author presented the means for drilling in deep water,[2] at the fall meeting of the Petroleum Division of the AIME at Los Angeles. His concepts then were based on the use of rigid foundations suitable for drilling in water up to 600 ft. deep. The present paper suggests a method for drilling in deeper water.

Possibilities and Problems of Drilling beyond the Continental Shelves

It being conceded that because restricted deep-water portions of the hydrosphere might contain oil in commercial quantities, and that at any rate it is pertinent to know more of the nature of the lithosphere beneath the hydrosphere, the possibilities and problems of drilling beyond the continental shelves should be set forth.

Drilling in open water would offer few if any advantages over drilling on land. These are:

1. The ocean transportation is available to deep-water drilling sites, and extensive pipe lines and roads are unnecessary.
2. Refinery facilities and markets perhaps are established on the near-by shore where adjacent fields on land are nearing depletion.
3. There is freedom from jungle pests and tropical diseases.
4. Competitive drilling is less likely.
5. Extensive areas attractive for development are not yet under lease or concession.

Disadvantages are great and numerous:

1. Storm hazards from wind and wave.
2. Expensive foundations, either rigid or floating.
3. Shutdown times because of weather.
4. Marine Regulations of Federal Bureaus in addition to customary regulations on land.
5. Frequent difficulty in moving men and materials to and from drilling platforms.
6. Extra precautions required in open sea.

For drilling in water more than 500 or 600 ft. deep, rigid foundations[2] become too costly, and floating foundations must be used, and they must meet the following requirements:

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[1] References are at the end of the paper.

1. The derrick floor and well head must be in the open air, as on land.

2. The conductor pipe, casing and drill pipe when in use must be under constant tension and not undulating with the waves.

3. The derrick floor and drilling platform must maintain a constant level even when loading or unloading material, or landing casing or drill pipe on the bottom of the well, or when injecting into or removing quantities of liquids from the well; and must not rise and fall with the waves.

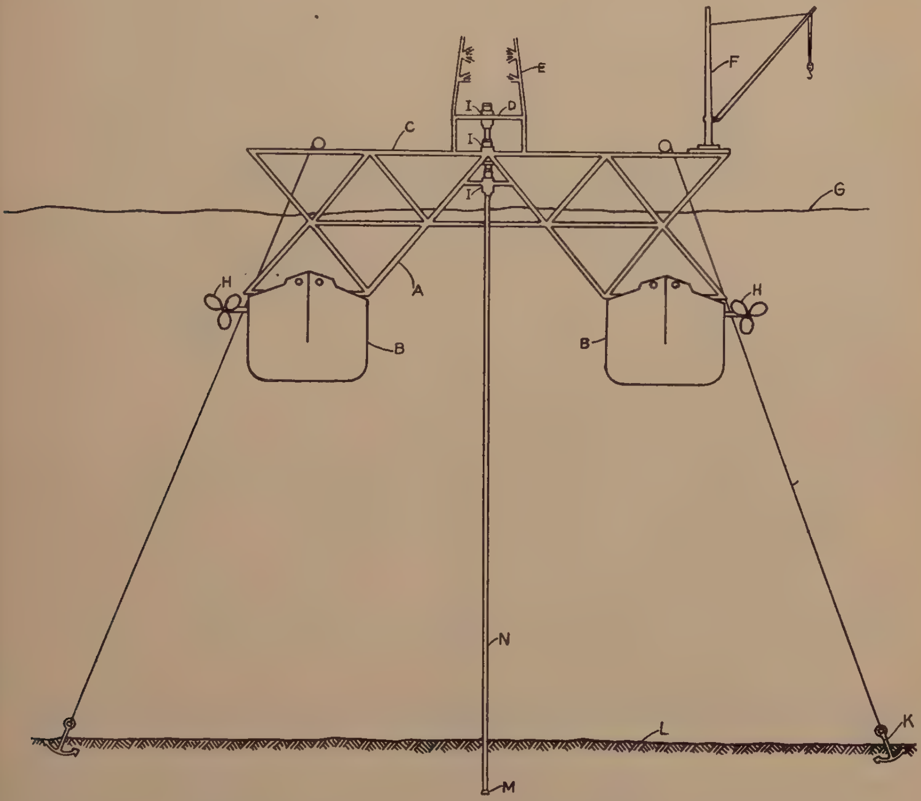

FIG. 1.—MARINE FOUNDATION FOR USE IN WATER DEEPER THAN 600 FEET.

A. Open-type substructure.
B. Hull.
C. Drilling platform.
D. Derrick floor.
E. Derrick.
F. Crane.
G. Sea level.
H. Propellers.
H′. Propellers for torque.
I. Hydraulic rotary tables.
J. Anchor line.
K. Anchor.
L. Sea floor.
M. Drilling bit.
N. Drill pipe.
O. Intermediate string.
P. Conductor pipe.
Q. Diaphragm to actuate valve.
R. Tubing to carry diaphragm liquid.
S. Mechanism by which diaphragm fluid actuates rod *T* to open and close valve *U*.
V. Diaphragm to start and stop motors driving propellers *H*.
W. Tubing to carry diaphragm liquid for controlling motors driving propellers.
X. Anchor hoist.

4. The foundation must be of the open type in the part of the structure that is subject to action of wind and wave.

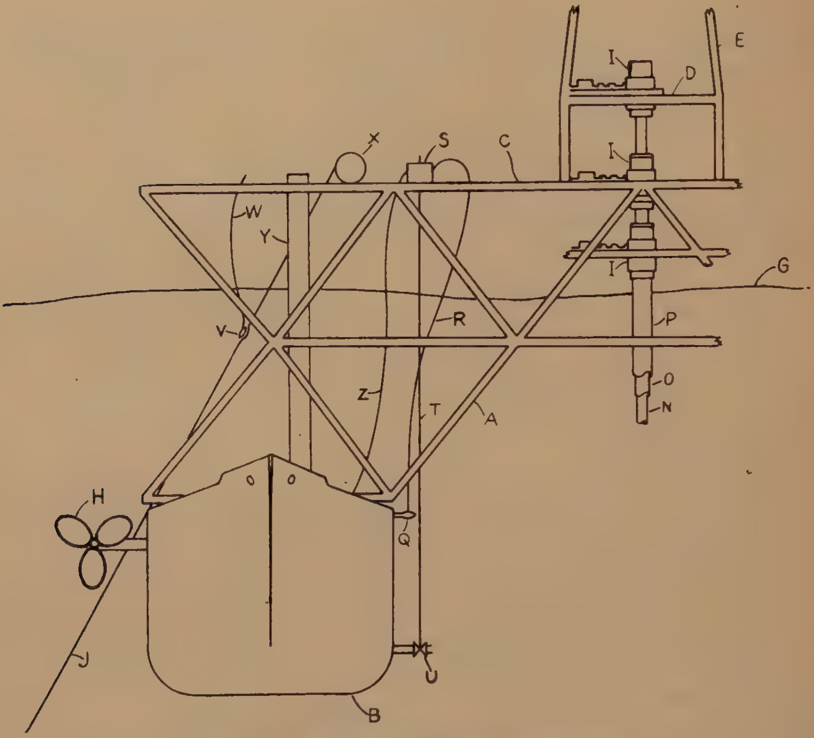

Fig. 2.—Front view marine foundation.
For legend see Figure 1.

5. The drilling platform must remain in a fixed position at all times, and must have means provided for overcoming torsion imposed by the drilling operation.

6. The foundation must handle all the loads amply for the drilling of the well or wells if several wells are drilled from one location, and must provide ample storage space for rotary mud, and space for fresh water and crude oil to cover the needs of several days, at all times.

7. It is understood that under all circumstances metacenter conditions must be such that the floating foundation cannot overturn.

8. Anchors must not drag.

The Foundation

A foundation meeting these requirements is set forth in Fig. 1. Item *A* is an open substructure supported on hulls *B*, which are sealed on the decks and are submerged sufficiently to escape wave action in storms. Drilling platform *C* is sufficiently above sea level to be safely above any storm waves, 40 to 50 ft. Referring to the more detailed illustration of Fig. 2, hull *B* may be entered through manway *Y*. To keep the drilling platform at constant level, diaphragm *Q* causes water to be admitted to storage in the hull if it and the drilling platform tend to rise, and to discharge water if sinking, the pumping mechanism being in the hull. To maintain the drilling platform in a level plane a minimum of four points must have diaphragm-controlled ballast stations, one being fore and aft in each hull to maintain an even keel* throughout. Probably it would be better to have duplicate stations at each point, for surety. Although items *Q*, *R*, *S*, *T*, and *U* are shown as external, in practice they would be contained neatly within the hull, together with the pumping mechanism, and the diaphragm element functioning for *Q* would be in a vertical cylinder or tube passing well above sea level and having small openings below sea level, so as to tend to cut down the effect of undulations of the waves.

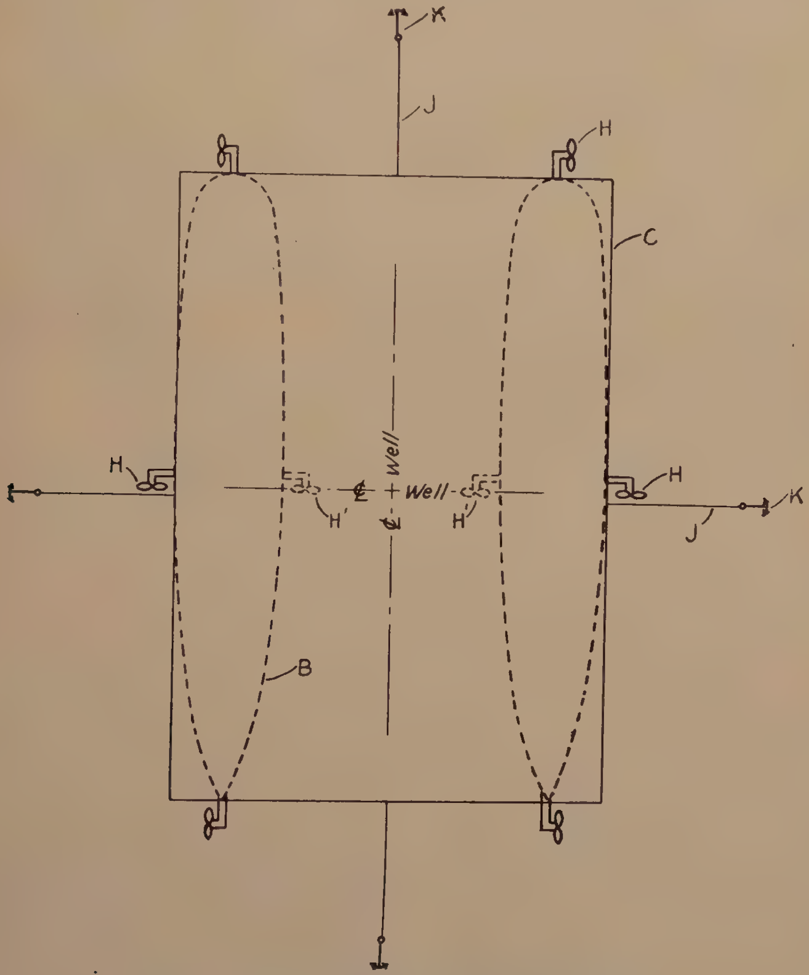

FIG. 3.—PLAN VIEW, FLOATING DRILLING PLATFORM.
For legend, see Figure 1.

Although theoretically the drilling platform would have no up and down movement, actually there probably would be a little. This would be undesirable for the casing strings *O* and *P* or drill pipe *N*.

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* The even-keel submarine, long a highly successful war machine, was invented by an American, Simon Lake, a half century ago, and during World War II he advocated large cargo submarines.

To keep these strings of pipe under constant tension, hydraulic rotary tables *I*, held under constant hydraulic pressure, should be provided.

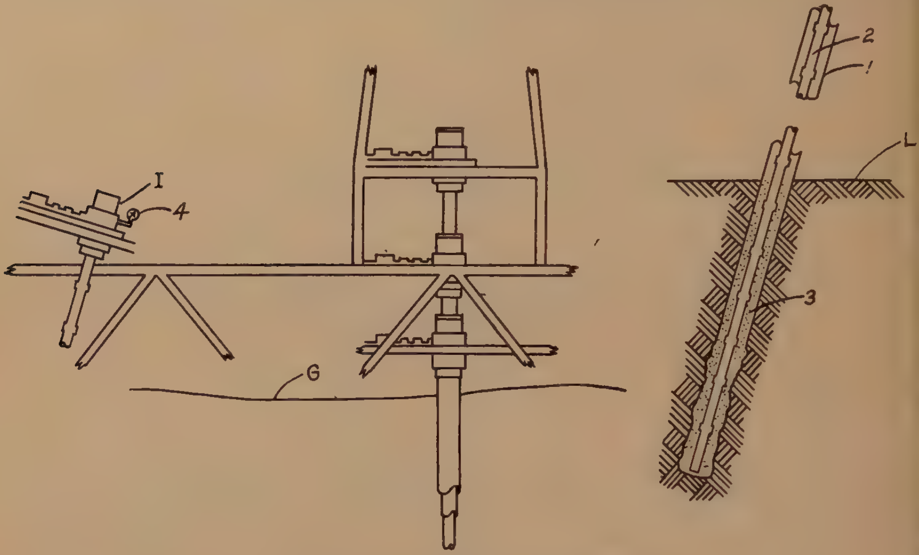

Fig. 4.—Pipe anchorage below the sea floor.
1. Conductor pipe for anchorage.
2. Buoyant anchorage pipe.
3. Anchorage hole.
4. Gauge.

The conductor pipe would be worked as far into the sea floor as possible, assisted by underdigging with retractable rotary bits.

To cut down anchor-cable tension from wind blowing against the foundation and equipment exposed above the water, a cable diaphragm *V* similar to those used with weight indicators is secured to cable *J* and tube *W* carries fluid to the control mechanism that operates reversible motors that drive propellers *H* in such manner as to relieve tension in the anchor cables.

Fig. 3 is a plan view of the floating drilling platform. When the rotary table is rotating, any torque action thereon should be met instantaneously with an equal and opposite torque applied through propellers *H′* provided for that purpose.

Manway *Y*, the means of entry to hull *B*, should be of as small a tube as conveniently would permit men to climb up or down the ladderway and a safety hatch should be provided beneath it. It would be best to have a manway fore and aft on each hull. Small-diameter manways offer less resistance to storm waves, which when cusping hit with terrific impact.[3]

Pipe for carrying electric lines, or oil, mud, or fresh-water lines into the hull, should be spaced apart and enter the hull separately, so as to offer less resistance to waves. The hulls should be large enough not only to provide ballast chambers of size sufficient to allow severa hundred tons variation of load but ample storage tanks for oil, mud or fresh water.

For ease of illustration, hulls of the shape shown were depicted, but it is understood that other forms might be more advantageous; for example, a cigar-shaped hull, or even spheres, the latter offering the same resistance in all directions.

Anchorage by Rigid Members in Tension

A foundation using cables and diaphragm mechanisms has been set forth. Such an ocean drilling platform using a minimum of vertical members exposed to wave would require 1000 hp. for stabilization in big ocean storm waves. If an attractive oil or gas reservoir should be encountered—for example, in Santa Barbara Channel, California—the means described might be replaced by tension members of 8⅝-in. bouyant drill pipe. The drill pipe would replace anchorage cables and would be anchored either deeply beneath the sea floor or on the sea floor by a suitably applied load.

Fig. 4 presents such an anchorage below the sea floor. The floating foundation would be fixed in place as set forth previously and as illustrated in Figs. 1 and 2. Hydraulic rotary equipment, designated *I* on Fig. 4, would be set at the proper place on the drilling platform, and a conductor pipe 1 would be landed at a suitable angle on the sea floor, and worked as far therein as possible with retractable bits. A releasing joint should be provided above but as near the sea floor as possible. With the conductor pipe in place, suitable hole could be made for anchorage. Since the sea water at the bottom of the deep sea is cold, approaching 0°C., the rock temperature at anchorage depth should be low, and after the anchorage hole is made a column of slow-setting cement could be spotted at the bottom thereof through the drill pipe. A string of 8⅝-in. buoyant pipe could be run and worked into the fluid cement and allowed to set. The conductor pipe could be parted at the releasing joint and recovered by the tedious process of stripping.

A plurality of such pipe anchorages could be placed in pattern around the platform. Pipe buoyancy may be provided either by having each joint an individually sealed chamber or by bailing the pipe until empty. The sealed-chamber method could be used, having the pressure in each joint equal to the hydrostatic pressure at the depth at which the joint would be used.

Hydraulic rotary tables or chucks would hold the pipe at its upper end and a pressure gauge used with the chuck would show the tension at all times. A pressure element in conjunction with each hydraulic chuck could be used to relieve some of the pipe tension by use of power, as described in the earlier discussion on the anchor cable. Buoyant 8⅝-in. pipes would have a maximum capacity of 800,000 lb., i.e., a safe capacity of 400,000 lb. Pipe joints should screw together but be made so that they cannot unscrew automatically.

A modification of the floating drilling platform set forth in Figs. 1 and 2, but having wide flat-bottomed hulls, might be lowered onto the sea floor by use of even-keel principles discussed previously, with the top of the hull at least 30 or 40 ft. below sea level, so as to be free from effects of storm waves. For the same reason the drilling platform should be about 40 ft. above sea level.

Protective Measures

The rapid improvement of helicopters, meteorology, radio, radar, and landing craft will add greatly to the safety of crews working with open-water drilling and producing equipment.

Anchor cables should be treated in the factory with a highly effective monomolecular layer anticorrosive and the upper portion, from a few hundred feet under water to the reel, should be sheathed in the same way as electric logging cables. Diaphragms and delicate working mechanisms should be made of noncorrosive materials.

There is no apparent means of protecting the floating foundation from the tsunami or diastrophic tidal waves.

CONCLUSION

It must be conceded that probably there are oil deposits under water one mile or more deep and that these might contribute valuable petroleum supplies where production is waning.

What appears to be a logical approach to drilling beyond the continental shelves has been set forth, but it must be emphasized that concerted and widespread thought may reveal better means.

Even though drilling in such deep water may not open commercially exploitable petroleum deposits, it is pertinent to the welfare of the nation that everything possible be learned of the nature of the lithosphere beneath the deep hydrosphere, so that if it is found to be one vast desert, devoid of resources for man, the latter must cease to be prodigal with the resources at hand.

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Advantages of Brines in Secondary Recovery of Petroleum by Water-flooding

By Richard V. Hughes,* Member AIME, and Rudolf J. Pfister*

(New York Meeting, March 1947)

Abstract

The necessity for getting more water into sands of low permeability in any secondary-recovery water-flood operation in order to recover all the available oil always has been a major problem. In the early days of water-flooding the addition of soda ash and caustic soda to fresh input waters was recommended and tried without success in the Bradford field. The most frequent difficulty was sand plugging. The use of natural and artificial brines often has been suggested for water-flooding, in the belief that laboratory observations of decreasing fresh-water throughput rates in measuring water permeabilities of consolidated sand cores might be partially explained by swelling of clays.

A review of available literature bearing on the subject and related laboratory experiments are presented herein, offering an explanation for failure in use of soda ash and caustic soda waters and supporting the recent concept that every water used for input purposes in the secondary recovery of oil should possess such physical and chemical characteristics as to keep the clay content of the producing sands in a permanently flocculated condition. Produced brines meet this requirement. Their use is recommended as a means of increasing intake rates of tight sands and oil recoveries, as a solution to brine-disposal problems, and as a means of conserving a natural resource.

Introduction

There is a general belief among those engaged in the secondary recovery of oil by water-flooding that one of the most important requirements for the success of any such project is an adequate supply of good, fresh water. Fresh waters have the advantages of being more easily stabilized than salt waters and of being usable about the lease for all purposes. The use of brines for water-flooding never has been given much consideration in the Pennsylvania Grade area. The use of brines in Mid-Continent operations has been considered largely as a substitute for fresh waters, which were economically unobtainable for many operations.

Estimated recoveries for some water-drive fields indicate that less of the original oil in place will be left upon abandonment than with the above-average practices used in Pennsylvania Grade water-flood operations. Lower residual oil saturations than 25 pct of the pore space following the water-flooding of Third Bradford sand cores in the laboratory are unusual. In comparison, water-flushed sands surrounding any virgin oil pool are found to be practically devoid of oil. Such lower natural residual oil saturations may be the result of a time factor much longer than economic under artificial water-flood operations, but neither the producer of primary oil nor the producer of oil by secondary recovery can obtain maximum recoveries unless full advantage is taken of all natural forces and

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* Director Production Research and Director Production Research Laboratory, respectively, The Pennsylvania Grade Crude Oil Association, Bradford, Pennsylvania.

natural conditions within the pools. Nature not only used salt brines to accumulate petroleum into the pools, but also continually drives the petroleum out of such accumulations by the same means. As Nature does such an efficient job of water-flooding using brines, and as brine disposal under State stream-pollution laws very often becomes a serious problem in most large oil fields, the present studies were initiated under the concept that oil-field brines are a natural resource that should not be wasted any more than natural gas, and that they possess definite advantages in comparison with fresh waters for water-flood operations. Studies of the literature supplemented by simple laboratory experiments and field observations confirm this concept.

Early Attempts to Improve Efficiency of Flood Waters

During the middle 20's, when water-flooding in the Bradford field started to go scientific, many producers and scientists were saying that if one's hands were dirty with oil one would not use just clean fresh water to cleanse them. With this thought in mind there resulted a great deal of laboratory and field experimentation to improve fresh input waters. Many patent applications were filed. All advocated the use of some additive intended to make the water cleanse the sand grains more effectively. The addition of small percentages of soda ash and caustic soda were most frequently advocated. Laboratory experiments utilizing these alkalies, silica, oil sands, and various crude oils proved to be very convincing at the time.

Such experiments were reported by Beckstrom and Van Tuyl,[1] who believed that the addition of sodium carbonate to fresh input waters was superior to the addition of strong and weak acids and other alkalies. Acid solutions, both organic and inorganic, either dilute or concentrated, were pronounced ineffective in releasing oil from sand grains. Strong acids were said to act as detergents in every case. Weak acids in 1:6000 solutions were found to be no more effective than fresh water. The use of a 1 pct solution by weight of sodium carbonate was found to give best recoveries. Nutting[2–6] carried out many similar and related experiments with respect to the surface activity of quartz, sand grains and other sand minerals with water and crude oils and advocated the use of carbonates also. On the whole the problem of increasing recoveries by water-flooding was viewed solely as one of stripping adhering oil films from the sand grains—and this viewpoint is questionable in the light of subsequent research. The petroleum trade journals all carried numerous feature articles between 1925 and 1927 describing tests being conducted in the Bradford field and stressing the importance of the soda-ash and related processes to the petroleum industry. The petroleum world was said to be watching the "Bradford experiment" with intense interest.

It did not take long for the Bradford experiment to come to a standstill. Plugging of the sands was the common reason given for failures. Deposition on the sand face and formation of harmful precipitates within the sands were believed to have caused the sharply reduced water-intake rates. Students of the problem noted that many producers paid little attention to the concentrations used. Some producers used very dilute solutions; others worked on the theory that if a little is good a lot would be much better. As a result, input wells were subjected to waters varying from barely alkaline to supersaturated solutions of soda ash. Thom[7] saw a possible relation between high recoveries obtained from the First Wall Creek sand in the Salt Creek field and the relatively high carbonate content of its edge waters, and warned of the dangers of harmful precipitates in flooding with soda ash.

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[1] References are at the end of the paper.

Beckstrom and Van Tuyl pointed out, in their first paper,[1] the necessity for studying sand conditions before using sodium carbonate solutions, especially with respect to the amounts of clay impurities and the nature of the cementing materials. Beckstrom[8] again stressed the need for obtaining all pertinent information, especially with respect to sand conditions, and Thom[7] stressed the need of scientific control of the tests by competent engineers.

Early workers on permeability measurements of sands noted that fresh and distilled waters showed decreasing throughput rates with time. Fancher, Lewis, and Barnes[9] in discussing similar observations stated:

> The discrepancy in the value of the permeability of the Bradford sand or any other when measured with water as compared to that obtained with air is probably due to the hydration and consequent swelling of clay within the sand. That the effect is chiefly due to hydration and swelling of the clay and not movement of the clay within the sample caused by the movement of the water with consequent plugging, is indicated by two experimental facts, namely the permeability is constant with time if the sand is saturated with water before test and secondly the permeability to air is constant with time.

Muskat[10] also believed that swelling of clays within the sand causes the discrepancies between air and water permeability values and cautioned that when water is employed for permeability measurements the low or end values should be reported as the permeability measurement.

Krynine[11] has found that the Third Bradford sands contain on the average 3 to 10 pct of clay with a maximum of perhaps 15 pct. Third Bradford sand pore walls, however, were said to be lined with clays in amounts ranging from 20 to 80 pct of the wall area. As the diameters of the pores decreased, the percentage of clay lining the walls was said to increase. He also estimated that nearly three fourths of the solid surfaces that come into contact with oil consists of clays. These clays were said to consist of extremely fine particles of biotite, illite (?), sericite, chlorite, and several other unidentified clay minerals. Waldo[12] has stated that the Bradford sand of the near-by Kane field has an even larger proportion of clay than the sand at Bradford. These high percentages and the predominating type of clay mineral in the Third Bradford sand were not known or suspected at the time of the "Bradford experiment."

BRINES SAID TO GIVE BETTER RECOVERIES IN KANSAS

Fresh waters treated according to today's most acceptable scientific methods for control of corrosion, organic growths, removal of harmful suspended and dissolved materials, and with an artificial pH on the alkaline side, very often show rapid declines in well-input rates with time. Plugging of the sand face has never been an adequate answer. The water-input rate should tend to increase with time, instead of to decrease, if the sand face is kept clean and oil is produced.

At the Fifth Annual Technical Meeting of the Bradford District research group, October 1940, it was pointed out by one of the producers that in Kansas 15 pct higher oil recoveries were being obtained with brines than with fresh waters. In view of such benefits, numerous tests were carried out at The Pennsylvania State College using Bradford-field connate waters, simulated brines, and Third Bradford sand cores that had been extracted and resaturated. Smith[13] summarized these investigations and concluded that in general oil recoveries were no more efficient for each permeability group of sands. Although he observed that brine throughput rates were higher than those for fresh water, he stated that the overall throughput rates for brines and fresh waters were found to be about the same if probable experimental errors were taken into consideration. Swelling of clays within the sand cores was considered as a possible, but insufficient, explanation for lower fresh-water throughput rates where they were observed.

In the meantime some theoretical aspects with respect to the use of connate waters for water-flooding were presented by Heck[14] with the hope "that. . .(Heck's paper). . . will start a controversy that will clarify this point." As a result of studies of papers by Nutting,[2] Kelley,[15] Kelley and Jenny,[16] and Grim,[17] he suggested that on theoretical grounds connate water may have a stronger wetting power on minerals in oil sands than fresh or dilute waters and its use would not only largely prevent the swelling of the clay minerals but under certain circumstances would also cause the clay masses to become more granular and more permeable. Heck suggested that in some cases it might be desirable to add calcium chloride to fresh flood waters. He also pointed out that the greater viscosity of connate waters as compared with fresh waters was one definite disadvantage for flood purposes. Smith[13] also called attention to the disadvantages of the greater viscosities of brines. Yuster[18] has suggested that, because of the possibility that clay will swell in fresh waters, there might be some advantages from an input viewpoint in using brines. Pennsylvania Grade operators have never given serious consideration to the use of brine, since oil recoveries in the laboratory were no better than for fresh waters and it was known that corrosion might be a serious problem.

Oil-field Clays are Dispersed by Fresh Waters

A series of three papers by Taylor,[19–21] of the School of Agriculture, Cambridge, England, dealing with a theory for the origin of petroleum prompted the premise of the present investigation that brines *are* superior to fresh waters for secondary recovery of petroleum. Taylor collected and analyzed clays and shales overlying and associated with oil-bearing sands from all parts of the world. He found that clays and shales associated with oil-bearing strata, irrespective of geological age or country of origin, are all alkaline and contain sodium clay as the characteristic constituent. He showed that when some sodium clay is placed in a funnel and treated with a solution of sodium chloride, the sodium clay will be found to be permeable, the clay particles being flocculated. When the sodium chloride solution is replaced by pure water, the rate of percolation decreases, the percolate contains deflocculated clay in suspension, the percolate becomes alkaline, and finally the sodium clay becomes impermeable. Taylor's hypothesis for the origin of petroleum, and some of his statements with respect to base exchange and the formation of clays and shales, were later questioned in the literature, but nothing has been noted refuting his above-stated principles.

Case[22] agreed with Taylor that sodium clays would be a natural result of calcium clays being carried to the sea and deposited upon flocculation by sea water, and that such sodium clays would remain stable and permeable in the presence of salt water but would become impermeable when subjected to fresh-water leaching. Kelley and Liebig,[23] in discussing the papers of Taylor and Case, stated that sodium clay is chemically unstable and that a bed of sodium clay will be preserved for a long time unchanged only if it is situated so as to be protected from action of solutions containing other cations. They point out that even very dilute solutions of calcium salts, such as calcium bicarbonate, will gradually convert sodium clay into calcium clay. Although sodium clays may be changed readily to a calcium clay, Kelley and Liebig emphasize that the process takes place with extreme slowness in nature because sodium clays are difficult to leach in place with fresh waters, owing to dispersion by fresh water and resultant impermeability.

INPUT WATERS SHOULD KEEP CLAYS FLOCCULATED

Taylor,[19-21] Case,[22] and Kelley and Liebig[23] have classified all clays into sodium, calcium, and hydrogen groups. Grim[24] classifies the major types of clays into kaolinite, montmorillonite, and illite groups, after the dominant mineral characterizing each.

Bentonites, which are so commonly used in preparing superior rotary drilling muds, owe their properties to the presence of the montmorillonite minerals. Kaolinites are believed to be relatively unimportant from an oil-production viewpoint.

Illites possess some of the characteristics of montmorillonites, especially with respect to base exchange properties, but to a much lesser degree. Illites when associated with producing oil sands and sodium bentonites are considered in this paper as belonging to Taylor's sodium clay group. Ambrose and Loomis[25] made an early study of some of the properties of Wyoming bentonites with respect to rotary drilling muds and pointed out the effects of pH control. No similar studies have been noted with respect to illites, although Fancher and Whiting[26] made a study of Hastings drilling muds, which were said to contain a large percentage of illite, and have evaluated such muds with respect to pH and many dispersing additives. Larsen[27] has presented some data on filtration characteristics of natural, partially deflocculated, and partially flocculated illite-bearing clays from California.

Garrison[28] has reviewed the parts crystal water, broken-bond water, and planar water play in the physical and chemical characteristics of clays and shales.

All these drilling-mud studies emphasize the principles of base exchange which are believed to have the same opportunity to occur within the sands during water-flooding.

Many other workers have demonstrated also that most clays are flocculated by natural salt brines and dispersed by fresh waters of alkaline characteristics under a wide range of pH. The superior rotary drilling mud owing its properties to well-dispersed clays may become worthless if diluted sufficiently with brines, on account of its change from a dispersed state to a flocculated state. Flocculated drilling muds form permeable filter cakes irrespective of thickness. Well-dispersed drilling muds form thin, relatively impermeable filter cakes. The mudding-off processes that take place on the sand face and within adjoining pores in a rotary drilling well have the same opportunity to occur within the pores of a producing sand during a water-flood operation.

Some of the chemicals added to rotary drilling muds to give them their desirable pH and filter-cake building properties are often added to fresh waters used for water-flooding for control of corrosion. Study of Taylor's theories[19-21] and answering papers,[22,23] drilling-mud literature and practices, and simple laboratory experiments prompted the concept that the ideal flood water should possess physical and chemical characteristics that will keep the clay material within the pores of the flooded sand in a permanently flocculated condition,[29] or must be treated to attain such a condition. As a result of additional laboratory experiments and field evidence, this concept—which also might be stated conversely; i.e., that input waters used for secondary recovery of oil by water-flooding should not disperse the clay content of the sands being flooded—is advocated by the authors as one of the basic requirements for every flood water. Produced brines meet this basic requirement even when considerably diluted with fresh waters. Typical simple laboratory and field experiments in support of this concept were carried out as described in the following pages.

SIMPLE LABORATORY EXPERIMENTS

Flocculation Tests.—Unextracted diamond cores from the Third Bradford sand, containing paper-thin lenses of clays and shales similar to the one illustrated in Fig 1, were broken (by pounding with a hammer on an iron plate) into fragments that would pass a 16-mesh sieve. The broken material was further crushed with an ordinary porcelain mortar and pestle. An effort was made by visual inspection to stop just prior to pulverization of the individual sand grains. The fraction of this crushed material that passed a 325-mesh sieve was considered as clay.

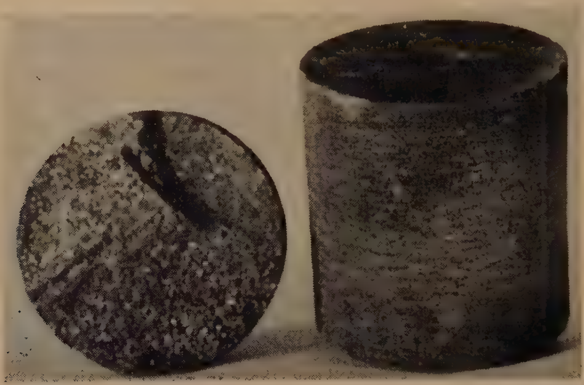

FIG 1—CORE OF THIRD BRADFORD SAND OF 20 MILLIDARCYS PERMEABILITY.
Bright spots on end view (left) are mica flakes.

For early experiments the fraction passing the 325-mesh sieve was separated into clays and silts by decanting off the dispersed material after vigorous shaking for several hours in distilled water. This step was eliminated because of the leaching action of the distilled water upon the clays, although it was noted that approximately 80 pct of the so-called clay fraction was actually silt.

Portions of the material passing the 325-mesh sieve, weighing ¼ gram each, were placed in 25-cc graduated mixing cylinders, which in turn were nearly filled with the water under test. Among the waters tested were distilled water, raw well waters, treated input waters, produced brines of various dilutions and concentrations, and numerous alkaline and acidic waters of varying pH. After thorough shaking, each mixing cylinder was allowed to stand at least 24 hr. Visual observations of turbidity and flocculating properties were made occasionally but were not scientifically recorded. Care would have to be taken in making such tests with clays having a high base-exchange capacity to use either a sufficiently small clay sample or a sufficiently large volume of the water under test.

Flooding of Diamond Cores.—Methods and measurement of water throughput rates for brines and waters of different pH values using unextracted sections of diamond cores have been described by Breston and Johnson.[30] Essentially, the equipment at the start consisted of the customary types of core holders for flooding diamond cores from outside in and from inside out. In the course of the first few tests it was noted that, contrary to mathematical formulas for radial flow, throughput rates were up to 400 pct higher when flooding from outside in than when flooding at the same pressure from inside out. The smaller surface area available for surface plugging may have accounted for some of the difference. All except the first six cores were flooded from outside in. The present flooding arrangement is illustrated in Fig 2.

It permits a core to be flooded with any type of water at different pressures by simple changes in supply connections. Uniform pressures are maintained by regulators utilizing compressed air.

Various lengths of unextracted diamond cores were used for all measurements. In all, 26 cores of Third Bradford sand, 5 of Bartlesville sand, 4 of Illinois Siggins sand, and one 18-in. core from the Franklin mine sand have been flooded with tap water, with treated fresh input waters taken from a Bradford lease, with Bradford field brines, and with artificial brines.

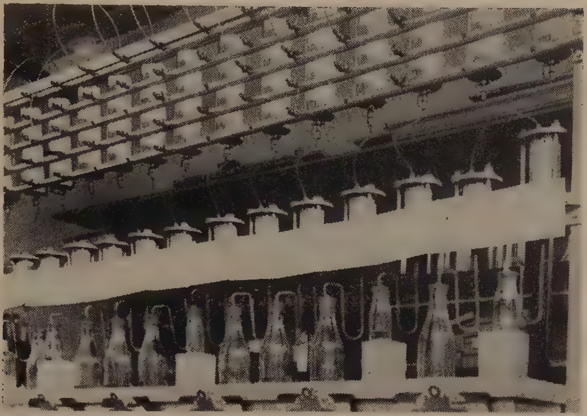

FIG 2—LABORATORY "FLOOD-POT" RACK FOR WATER-FLOODING SECTIONS OF DIAMOND CORES WITH VARIOUS WATERS AT DIFFERENT PRESSURES.

RESULTS OF LABORATORY EXPERIMENTS

Flocculation Tests.—The flocculating or the dispersing properties of any water upon the clay can be observed readily by the flocculation tests, which show that many raw and treated fresh waters disperse the clays and may hold them in such condition indefinitely, and that brines, even when greatly diluted, cause the clay to form into small aggregations or "flocs," which settle quickly to the bottom of the cylinder and leave clear brine above. Typical tests are shown in Fig 3. Under the concept that any flood water should keep the clay content of the sands in a permanently flocculated condition, the quicker the "riled" contents of the mixing cylinder clear, the better in general the water should be for flooding.

Flooding of Diamond Cores.—The comparative results obtained in flooding the sections of sand cores with various fresh waters and brines are shown in Table 1. In all except three cases (flooding from inside out) there were appreciable gains in brine rates in comparison with fresh waters. The average ratio between the brine and fresh-water throughput rates averaged 1.8 for Third Bradford sand cores, 1.3 to 1.7 for the one Franklin mine Venango sand core, 4.0 for the Bartlesville sand cores, and 2.2 for the Siggins sand cores. Data are not shown, but rates were reversible by reflooding with the first water.

In addition to the tests shown in Table 1. a virgin diamond core of Third Bradford sand was flooded with the produced brine whose flocculating property is shown in Fig 3, and which has a chloride content of only 2500 ppm, followed by the regular lease fresh water. The final brine throughput rate was 0.29 cc per min in comparison with 0.20 cc per min for the fresh water. The brine-fresh water ratio of 1.5 supports the fact that concentrated brines are not necessary to keep the clay content of the

TABLE 1—*Comparative Results*

Core No.	Pressure, Cm Hg	Air Perm, Md[a]	Flood Rates Cc per Min				Ratio Brine to Fresh-water Rate
			Filtered Tap Water	Treated Lease Input Water	Produced Bradford Brine[c]	Artificial Brine[d]	
BRADFORD THIRD SAND							
1	120	20.0		3.8	6.0		1.6
2	120	20.0		5.5	7.8		1.4
3	120	20.0		4.8	7.5		1.6
6[b]	225	11.0	0.03			0.10	3.3
2[b]	225	20.0	0.23			0.25	1.1
10[b]	225	10.0	0.24			0.30	1.3
1[b]	225	20.0	0.22			0.22	1.0
11[b]	225	18.0	0.21			0.20	1.0
12[b]	225	25.0	0.17			0.15	0.9
7	225	2.0	0.21			0.39	1.9
9	225	3.0	0.23			0.39	1.7
8	225	1.5	0.06			0.07	1.2
13	225	0.33	0.004			0.005	1.2
4	225	11.0	0.30			0.79	2.6
14	225	16.0	1.50			5.0	3.3
47	102	2.6–7.8		0.15	0.63		4.2
48	51	7.8–5.2		0.31	0.36		1.2
49	51	8.7–22.7		0.21	0.26		1.2
50	51	1.7–5.7		0.47	0.70		1.5
51	225	0.1–0.06		0.014	0.03		2.1
52	102	0.11		0.006	0.010		1.7
53	12.5	54.0–66.0		0.94	1.71		1.8
58	102	0.12–7.6		0.077	0.189		2.5
59	12.5	7.6–20.7		0.019	0.033		1.7
60	225	9.2–0.6		0.007	0.012		1.7
							Ave. 1.8
FRANKLIN MINE CORE (18 INCHES LONG)							
	45 psi.		0.3		0.5		1.7
	200 psi.		2.15		2.70		1.3
BARTLESVILLE SAND							
27	225	4.3	0.06			0.46	7.7
28	225	28.3	3.5			10.0	2.9
30	225	35.2	3.0			9.0	3.0
31	225	4.4	0.03			0.15	5.0
32	225	22.0	3.2			3.8	1.2
							Ave. 4.0
ILLINOIS SIGGINS SAND							
23	225	24.1	1.1			1.6	1.5
24	225	73.3	2.0			4.0	2.0
25	225	115.6	2.0			5.0	2.5
26	225	100.6	1.5			4.0	2.7
							Ave. 2.2

[a] Two values indicate measurements made off each end of core; single values are one determination.
[b] Flooded from inside out.
[c] Approx. 60,000 ppm Cl.
[d] Approx. 50,000 ppm NaCl.

sands in a flocculated and more permeable condition.

FIELD OBSERVATIONS

In the Bradford field, during the use of the water-input profile-measuring device whose measuring principle is based upon the following of a moving fresh-water-brine interface throughout the sand section of an input well, it has been noted that the sands take brines at a much faster rate than they take fresh water.[31] Gains of 20 to 25 pct are indicated at the same pressures. Scattered tests have been made in the Bradford field measuring the over-all input rate of brines in comparison with the

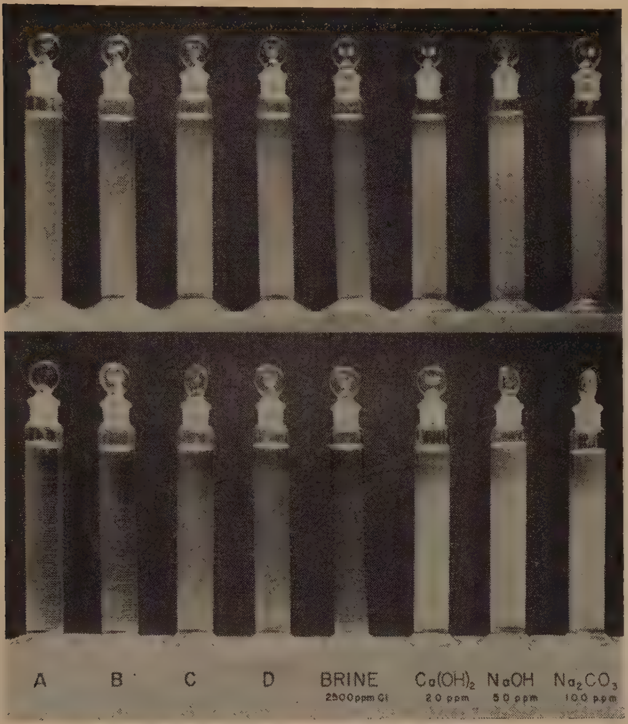

FIG 3—TYPICAL FLOCCULATION TESTS.

A, *B*, *C*, and *D* are regular input waters from four leases. Brine sample is from a producing well. Remainder are distilled water to which chemicals were added.

Upper: 1 hour after shaking.
Lower: 6 hours after shaking.

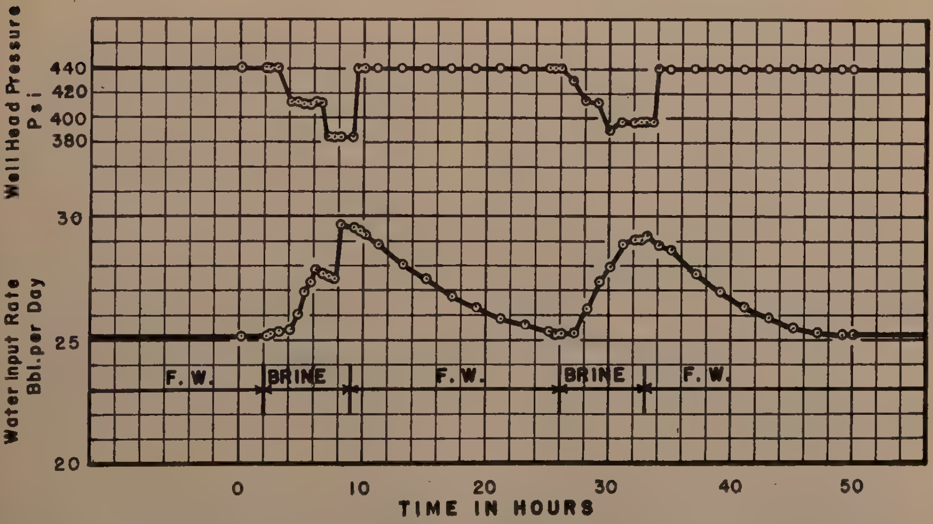

FIG 4—WATER RATES MEASURED AT INPUT WELL SHOWING SANDS TAKE 20 PER CENT MORE BRINE AT DECREASED WELL-HEAD PRESSURE.

regular lease fresh water. One such test is shown in Fig 4, which was carried out by inserting a brine lubricator in the system so that the input water could be switched from fresh water to brine without releasing sand-face pressure and causing backflow.

The brine not only entered the sand at a higher rate, but the relative permeability of the sand section to brines was increased to such an extent that the sands took sufficient brine to lower the well-head pressure. When the switch was made from brine to fresh water, the input rate showed a gradual drop back to normal with a corresponding increase in well-head pressure back to normal. In this one well the brine rate was approximately 20 pct higher with a decrease in well-head pressure from 440 psi to 390 psi. The marked increase in fresh-water rate upon switching from brine to fresh water is explained partially by the decrease in sand-face pressures during injection of the brine and partially by the residual brine pickup by the fresh water. The fresh water as it picked up less and less residual brine gradually fell back to its normal rate.

OTHER CORROBORATIVE LABORATORY INVESTIGATIONS

Sixteen extracted and artificially oil-saturated cores of Third Bradford sand were water-flooded at the Mineral Industries Experiment Station of The Pennsylvania State College, to determine the relative oil recoveries using brines and fresh waters.[13] Relative throughput rates for brine and fresh water calculated from these observations are given in Table 2 and show that, on the average, excluding the observations on core 16, the brine throughput rate is 2.8 times that of fresh water, which is considerably higher than the average for Third Bradford sands given in Table 1.

Johnston and Beeson,[32] in studying the permeability of hundreds of reservoir-sand samples from 23 oil fields, mostly in California, noted great variations between relative permeabilities to fresh and saline waters. Their values of the ratio of the fresh to saline-water permeabilities range from nearly zero to 1.0, which if expressed conversely—that is, the ratio of saline waters to fresh waters—would range from 1.0 to an almost unlimited ratio. They also cite a number of values of the relative permeabilities of fresh waters in comparison with waters of various salinities. The relative permeability on the whole is greater the higher the chloride-ion concentration and with as little as 1710 ppm is still much higher than for fresh waters.

TABLE 2—*Relative Throughput Rates*[a]

Core	Permeability, Md	First Flood Medium	Final Fresh-water Rate, Cc per Sec	Final Brine Rate, Cc per Sec	Ratio Brine Rate to Fresh-water Rate
1	0.65	Brine	0.00123	0.00434	3.5
2	0.71	F.W.	0 000555	0.00136	2.5
3	2.70	Brine	0.0793	0.767	1.0
4	2.50	F.W.	0.040	0.0386	1.0
5	5.80	Brine	0.344	0.0744	4.6
6	5.74	F.W.	0.217	0.205	0.9
7	8.33	Brine	1.15	0.300	3.8
8	8.88	F.W.	0.260	0.612	2.4
9	12.2	Brine	0.133	0.450	3.4
10	12.9	F.W.	0.238	0.434	1.8
11	17.1	Brine	0.934	2.72	2.9
12	18.6	F.W.	1.80	1.10	0.6
13	28.2	Brine	0.800	4.78	6.0
14	26.6	F.W.	0.282	1.87	6.6
15	74.6	F.W.	1.57	2.34	1.5
16	77.5	Brine	0.195	11.4	(58.0)
					Ave. 2.8

[a] After Smith.[13]

Larsen,[27] in studying the permeability of clay filter cakes, states:

> Not only do the filter-cake permeabilities of clays differ widely from clay to clay, but the same clay is capable of giving widely differing permeabilities depending upon the state of aggregation of the particles comprising the filter cake, which in turn is a function of the state of flocculation or deflocculation of the clay.

He has presented the data shown in Table 3, which corroborate those in Tables 1 and 2.

TABLE 3.—*Filter-cake Permeabilities*[a]

TREATMENT OF SUSPENSION	FILTER CAKE PERMEABILITY
1. 5 pct Hector (Calif.) bentonite in water:	
Partially deflocculated with $(NaPO_3)_6$	0.7
No treatment	1.2
Partially flocculated with MgO	8.1
2. 51 pct clay No. 34 (a colloidal, illite-bearing California clay):	
Partially deflocculated with $(NaPO_3)_6$	1.0
No treatment	1.2
Partially flocculated with MgO	2.4

[a] After Larsen.[27]

GENERAL DISCUSSION

It is well known that clay minerals of the montmorillonite type have considerably higher base-exchange capacities than those of the illite type. It has been shown that the clay content of Third Bradford sands contains an important percentage of illite-type minerals,[33] which confirms previous conclusions of the authors based upon the geological history of northwestern Pennsylvania and the presence of large percentages of mica in Third Bradford sands and shales. The presence of illite-type clay minerals in the Illinois Siggins sands has been determined also.[34] Important amounts of montmorillonite-type clay minerals are not indicated in either sand. Knowledge of the geology of the California oil-producing areas would indicate that the sands tested by Johnston and Beeson[32] probably carried large percentages of montmorillonite-type clay minerals, which would explain the extra large ratios between saline and fresh-water permeabilities in comparison with ratios obtained using sands from Oklahoma, Illinois, and Pennsylvania.

On the whole, the addition of some alkalies to raise the pH of fresh input waters for corrosion control is not believed to be good practice from the viewpoint of water-input rate. It tends to disperse the clay content of the sands. The principles of base exchange, in view of the clay content of most producing sands, offers a logical explanation for failure of the "Bradford experiment." The percentages of illites and montmorillonites in producing sands has a very direct bearing on whether any sand can be flooded efficiently with fresh waters. The higher the percentage of illites, and especially the higher the percentage of montmorillonites, the greater the probable decrease with time in fresh-water input rates.

Until a better flooding medium is found, some of the outstanding characteristics of produced brines should be considered by every water-flood operator:

1. Produced brines seldom exceed a pH of 7.5 on the alkaline side, and are rarely below 6.5 on the acid side.
2. Produced brines have the property of keeping the clay content of the producing sands of marine origin in a flocculated and permeable condition.
3. Produced brines are oxygen-free until after they leave the formation.

Produced brines are being used successfully in many water-flood operations outside the Pennsylvania Grade area. Where they are kept oxygen-free or are sufficiently deaerated, corrosion has been no more troublesome than with fresh waters.

SUMMARY AND CONCLUSIONS

Literature dealing with clays and drilling muds and laboratory and field observations offer an acceptable explanation for differences in fresh water and brine throughput rates of sands containing clays of the illite and montmorillonite types, which occur in various percentages in producing oil sands. Sands whose clay content is predominantly of the montmorillonite type were not tested, but because of the greater base-exchange capacity of montmorillonites in comparison with illites still greater differences between brine and fresh-water rates would be anticipated for equal clay content in the sands. As it may be postulated that few producing oil sections or sands are free of clays, it is necessary for efficient water-flooding of such sands to know the type of clay present and the effects of fresh input waters upon it.

Produced brines should prove superior to fresh waters for input purposes on every water-flood project. This would hold true especially where the pH of the fresh waters is naturally on the low alkaline side or is raised to low alkalinity by addition of chemicals to aid in preventing corrosion. There are primary recovery projects where produced brines are returned to the producing sands, others where produced brines are disposed of in nonproductive sands. All produced brines are a natural mineral resource, which should be utilized and, like gas, should not be wasted or otherwise disposed of. They should be returned to oil-producing formations to aid in recovering more oil. Sands of low permeabilities taking insufficient fresh water to produce their recoverable oil during the economic life of the operation should produce more oil in the same period by the use of brines, because of their higher input rates.

In conclusion it may be stated that the injection of produced brines on a secondary-recovery project should:

1. Keep the clay content of the producing sands in a permanently flocculated condition.
2. Increase input rates at the same pressure.
3. Permit wider well spacing in many areas.
4. Increase oil recoveries from sands of low permeabilities.
5. Help to solve State stream-pollution problems.
6. Support the principle of conservation of natural resources.

ACKNOWLEDGMENTS

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DISCUSSION

K. B. Nowels.*—The paper by Hughes and Pfister describing the advantages of brines in secondary recovery of oil by water-flooding is a noteworthy contribution to the technology of flooding. Their presentation of laboratory data showing that the injection of produced brines will keep the clay content of the producing sands in a permanently flocculated condition will lead to more efficient water-flooding. That such a flocculated condition will permit increased input rates is of great importance in field practice.

It is my understanding that there has been some field confirmation of their laboratory findings, which indicate that either salt water or an acid water with a pH value of 3.5 to 4.5 resulted in higher sustained throughput rates than did normal fresh water.

The writer has had an experience in the field that substantiates the research work of the Pennsylvania Grade Crude Oil Association. In March 1941 when water was being introduced for the first time into the oil sand of a newly developed water-flood in the Woodson field of Throckmorton County, Texas, considerable difficulty was experienced with plugging. Fresh, filtered lake water was used, but all the 18 input wells suffered a drastic reduction in intake rate, as shown in Table 4, where the intake data on six of the wells are shown.

TABLE 4—*Intake Data*
BARRELS PER 24 HOURS

Date	Well No. 1	Well No. 2	Well No. 3	Well No. 4	Well No. 5	Well No. 6
Feb. 28	3	15	17	3	3	25
Mar. 1	30	23	21	17	12	29
Mar. 2	12	13	16	0	24	19
Mar. 3	13	16	11	5	18	1
Mar. 4	10	0	13	1	17	26
Mar. 5	7	1	7	1	10	8
Mar. 6	6	1	0	1	3	7
Mar. 10	6	1	1	1	0	1
Mar. 11	6	6	6	6	10	10
Mar. 12	5	1	1	1	3	6
Mar. 13	3	1	1	1	0	4

Although the water was carefully controlled at the filter plant, it was felt that the chemical feeder might have introduced

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[*] Consulting Petroleum Engineer and Geologist, Abilene, Texas.

more lime than was proper for a short period of time; consequently one of the commercial acidization companies was called out on March 14, 1941, for the purpose of acidizing all the input wells. Approximately 50 gal of 65 pct acid (hydrochloric) was pumped into each well, then it was reconnected to the water-pressure system at once, so that the acid could be "chased out" of the tubing into the sand. The pressure carried on the system was approximately constant both before and after the use of acid.

Immediate results were obtained and all input wells were "opened up" so that expected normal intakes prevailed (Table 5).

TABLE 5—*Intakes after Acid Treatment*
BARRELS PER 24 HOURS

Date	Well No. 1	Well No. 2	Well No. 3	Well No. 4	Well No. 5	Well No. 6
Mar. 15	49	4[a]	41	15	28	35
16	77	32[a]	12	46	111	36
17	62	0[a]	48	0[a]	111	26
18	58	1[a]	37	61	117	9
19	62	58	38	93	60	49
20	57	100	39	72	140	30
21	44	69	37	0[a]	110	27

[a] Well pinched.

No further trouble was experienced with this group of wells after the one acid treatment. At a later time, when additional acreage was developed for flooding immediately adjacent to this first flood, similar "plugging" was experienced, and this was again counteracted by acid. This time, however just a few gallons was used in each well. It was introduced by gravity and the pressure system utilized as before in "chasing" the acid down. Where only a few gallons of acid were used this way in each well, it was necessary to repeat the "dose" some weeks later. This may indicate that a larger treatment of 50 gal per well might do more permanent good.

The writer now feels that the difficulty with "plugging" was caused by swelling of the clay materials by fresh water within the sand, as mentioned by Messrs Hughes and Pfister. The use of acid probably put these clay materials into a flocculated condition and led to normal intakes.

Examination of cores from the sand at the time by means of a magnifying glass disclosed the presence of a bluish gray claylike material mixed in with the sand grains. The use of acid in the Woodson flood and others in near-by territory for the correction of input wells was among the first, if not the first, adaptation of acid in water-flooding, although the basic reasons for its success were then unknown.

R. V. HUGHES and R. J. PFISTER (authors' reply).—The cause of subnormal initial water-input rates generally has been ascribed to improper cleaning out following drilling or shooting, if the latter is practiced. Many producers have considered the problem to be due entirely to a dirty sand face if the well has not been shot. If the well has been shot, it generally is considered due to the driving of mud into the sand. Where water tamps are used for shooting, it has been believed inadvisable to use more water than would be ejected from the hole by the shot in order that silts may not be carried into the producing formation immediately following detonation by the hydrostatic head of the water tamp. Mr. Nowel's experiences and explanation indicate what may prove to be a more common cause of subnormal initial input rates; namely, the creation of a low-permeability zone about the well bore by base-exchange reactions between fresh waters and the clay content of the producing sands. Acid treatment has been used to remedy "water blocks" in primary recovery operations. Many other factors enter into the beneficial results obtained by acidization of old sand wells, especially those used for water input.

It is preferable to prevent the formation of "water blocks" in all drilling and well-completion operations. Low-loss drilling muds are the first step, particularly where rotary tools are used. Produced brines, preferably from the same formation, or low pH waters for drilling in low-pressure formations, for cleaning out, and for water tamping where wells are shot, have been recommended as preventive measures.

Considerable research is being carried out in the laboratory and in the Bradford field with respect to the possibilities of using low pH waters for flooding. There is much in favor of their use. Throughput rates of low pH waters in the laboratory usually are higher than those for produced brines, but the problems of corrosion and the probability of other than base-exchange reactions occurring within the sands need much additional study.

Interpretation of Well Test Data in Gas-condensate Fields

By James O. Lewis,* Member A.I.M.E.

(Chicago Meeting, February 1946)

Abstract

The operation of gas-condensate fields is comparatively new and involves physical principles with which the industry was not previously familiar. It has been necessary to devise methods for testing gas-condensate wells and to correlate laboratory and field data. In this paper new methods are advanced for interpreting well G.P.M.† tests whereby dilution by dry gas can be estimated and information supplied on revaporization of condensates by dry gas. Inaccuracies in well test data are discussed. Changes in flow rates can cause changes in the G.P.M. of the effluent and it may take some time for a well to become stabilized after an important change in flow rate. Retrograde tests as usually conducted cannot be directly compared with field G.P.M. data, because the retrograde tests usually include solution gas in the condensates, which are reported on the cumulative basis whereas field data (G.P.M.) usually report pentanes plus on a rate or instantaneous basis.

Introduction

Though long known to physicists, the phenomena of retrograde condensation became known to the oil and gas industry only in recent years, when deeper drilling disclosed that the behavior of vapors under changing pressures was different in high-pressure reservoirs than under the low-pressure operations with which the industry was familiar. These deep, high-pressure reservoirs in which condensation and vaporization behaved inversely to the accustomed manner became known as "gas-distillate," or preferably "gas-condensate" fields. Partly to prevent precipitation and retention of liquids in the reservoir, but still more to prevent the waste of residue gas, the operation known as "recycling," or preferably "cycling," was instituted, in which the residue gas is reinjected into the reservoir, thus maintaining pressure and driving the wet gas to the producing wells.

For lack of field experience to serve as a guide, the industry had to assume that theory and laboratory experiments could accurately forecast retrograde behaviors in operating these gas-condensate fields, but it is obvious that these assumptions should be checked at the first opportunities against actual field experience. To make such checks, it is necessary to accumulate a large quantity of reliable field data, but experience has shown that it is difficult to obtain reliable field data and that the laboratory data as usually presented are not in directly comparable form. The problems of correlation involve the complex phase behavior on the one hand, and a knowledge of field data and a visualization of underground conditions on the other hand. This paper is an approach from field experience.

The purposes of this article are to discuss the sources of uncertainty in the data and to present methods of analyzing, interpreting and correlating laboratory and field data. Data mostly from lower Gulf Coast fields are presented, from which some conclusions can be derived, but better data from more sources than those available to the writer will be required before satisfactory answers to many questions can be obtained. This paper is presented to stimulate the analysis and publication of data from other fields, the reexamination of field and laboratory methods, and the taking of more complete and reliable field tests. For these purposes, the writer presents some speculations that otherwise would not be appropriate.

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† Gallons of natural gasoline per 1000 cu. ft. of gas.

ORIGINAL COMPOSITION OF THE GAS

The reservoirs to which this study applies are those in which the gas occurs originally under pressures well above the retrograde point, and when pressures are reduced some of the less volatile hydrocarbons will condense. The retrograde point will average about 900 lb. per sq. in. abs. in the shallower reservoirs, and will be much higher in the deeper reservoirs. Generally the gas in reservoirs less than 4000 ft. deep do not show important retrograde condensation.

The capacity of a gas to hold the less volatile hydrocarbons in vapor phase is dependent upon the pressure and temperature and upon the proportion and distribution of the hydrocarbons of intermediate volatility. As the capacity increases with pressure and temperature, the content of condensable vapors per thousand cubic feet of gas generally, but not invariably, increases with depth. As the capacity also depends upon the total composition and the distribution of components, there can be wide variations in the content per thousand cubic feet of gas of condensable hydrocarbons in gas that occurs at the same pressure and temperature. Olds, Sage and Lacey[1] have shown how the capacity to hold the less volatile hydrocarbons in vapor phase can be reduced by removal of the propane and butanes from the gas.

Higher pressures and temperatures, and higher percentages of hydrocarbons of intermediate volatility, can hold hydrocarbons of lower volatility in vapor phase. The deeper reservoirs, or reservoirs with gases containing greater percentages of ethane, propane, and butanes, tend to produce condensates of higher specific gravity and of higher end point.

Not all gases are fully saturated with vapors of heavier hydrocarbons under original reservoir conditions. Where the gases are undersaturated, the pressure can be reduced to some degree, depending upon the degree of undersaturation before vapors begin to condense. The pressure at which the change from vapor to liquid phase begins is known as the "retrograde dew-point" pressure. This may be determined from the history of G.P.M. tests, or from laboratory determinations. Because of the uncertainties in sampling, and because of the difficulties in determining the dew point in the laboratory apparatus, the dew-point pressure should be accepted with some latitude for possible error.

The original composition of a gas has resulted from the conditions of origin, migration, and accumulation. In course of geologic time, it is possible for reservoir pressures and temperatures to have changed, hence the capacity of the gas to hold liquids in vapor phase can have changed. If pressures and temperatures have been increased, the gas may have become undersaturated unless it has been in close contact with oil; if pressures and temperatures have decreased, vapors can have condensed and have wet the sand grains. It is unlikely that exactly the same pressures and temperatures have persisted throughout geologic time since accumulation, hence it is likely that a sand found to contain saturated gas will also contain small amounts of liquified vapors. It has also been often noted from core tests that the sand in a gas reservoir, especially low on the structure, may contain a small percentage of immobile oil.

Observations indicate that it cannot safely be assumed that the gas in a reservoir was originally of uniform composition throughout. It has been found that notable differences in the content of condensable hydrocarbons can be found within the same reservoir. In the Comstock sands of the Stratton-Agua Dulce field, Nueces County, Texas, the original G.P.M. varied from 0.8 to less than 0.3 within 4 miles. In another field the G.P.M. (butanes plus) varied from 6.0 to 1.3 within the same reservoir. Usually the original G.P.M. varies from well to well within each reservoir, though it has been often impossible to tell how much of this variation was due to sampling errors and how much to differences in original composition.

There can be several causes for variation in original composition. Within a large field such as Stratton-Agua Dulce, the gases could have originated in places and followed paths so widely separated that they could be quite different in composition when they enter the reservoir. The gases close to an oil contact are often found to be richer than gases more distant from the contact. In reservoirs of high relief, the pressures and temperatures at the top of the structure will be less, hence the capacity of the gas to hold vapors will be a little less; also, gravity stratification of the hydrocarbon gases can have a small part.

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[1] References are at the end of the paper.

Whatever may be the original causes for the differences, mixing by diffusion is so slow in the absence of turbulence that the gas may not reach uniform composition even in geologic time. A well-known example is the Amarillo field, Texas, where sour and sweet gas have been in free contact for geologic ages.

Analysis of Reservoir Conditions

In discussing the elements that enter into the problems of securing samples and interpreting the tests later in the life of the field, it is desirable to visualize what goes on in the reservoir, though, necessarily, this involves some speculation.

In a reservoir that is not being cycled, the gas flows radially from the perimeter of its drainage area toward the well with increasing velocity and pressure gradients. Because of the reduced pressures, retrograde conditions will increase in severity toward the well. The gas flow causes some reduction of temperature near the sand face but no appreciable reduction in the body of the sand, and the over-all effect is unimportant. As the well is approached, the pressure and velocity gradients increase rapidly and cause a pressure sink immediately around the well. This pressure sink is not sharply defined and varies with the flow rate. For the same flow rate it is more pronounced in thin or tight sands. When the well is closed in, the gas flows in until the pressure at the well becomes nearly the same as for the surrounding areas. In this paper, the pressure sink is defined as the area that becomes filled up when the pressures level off after the well is shut in. The conditions in the pressure sink are subject to large and rapid decreases or increases dependent upon flow rates, whereas the conditions in the main part of the reservoir change slowly and pressures are almost always continuously downward.

The gas nearest the well is produced first and is then replaced by gas flowing in from more distant parts of the drainage area. If the well is abandoned when 90 per cent of the gas has been produced, it is approximately true that all of the produced gas came from the 90 per cent of the drainage area nearest the well and that the whole drainage area is left filled with the gas that originally was in the remote 10 per cent of the area, none of which was produced. Where there are variations in the original composition of the gas within the drainage area, the composition of the effluent may be changed during the life of the well and confuse the interpretation of the retrograde effects. It is believed such changes have been important in some instances.

As the well is approached, increasing quantities of gas must flow through each pore to reach the well, and near the sand face many thousand times as much gas must pass through each pore as it originally contained. The larger the drainage area, the more gas will be passed through each pore before the gas enters the well. All the produced gas must pass through the pressure sink and be subjected to the maximum retrograde conditions that occur there.

If reduced to the liquid state, the condensable components of the gas would saturate but a minor portion of the pore space in which the gas originally occurred. For gas with a content of 1.0 G.P.M. at 3000 lb. per sq. in. abs., the liquid phase would occupy less than 3 per cent of the pore space; at 4500 lb. per sq. in. abs. and a content of 5.0 G.P.M., the liquids would saturate about 20 per cent of the pore space. However, not all of the vapors are ever condensed but always in the reservoir the liquids will be swelled by absorbed gases. For purposes of visualization, the two effects can be considered to offset each other approximately.

Even with the richest gases, it is unlikely that in the more remote parts of the drainage area the sands will ever reach a liquid saturation that will permit liquid flow, particularly as much of the gas will have left this area before the most severe retrograde pressure has been reached. It would appear that most of the liquids deposited in the more remote areas will be permanently lost. However, the conditions nearer the well, where many times the original gas is passed through each pore, are quite different. Near the sand face, the pores can become supersaturated even in a lean gas reservoir. After the sand has reached equilibrium saturation, all the condensates deposited thereafter will be carried forward to the well in liquid phase. It can be expected that the sand nearest the well will first become saturated and that the saturated area will continually enlarge as more gas is flowed through it and as pressures are reduced, until vaporization in the normal region begins. It can also be expected that the richer gases will saturate the pressure sink faster than lean gases. It has been suggested that the saturated area may be spread by capillarity or by gravity drainage downdip.

The percentage saturation at which liquid flow can begin in a sand will follow the usual laws of two-phase flow through water-wet porous media. The saturation will be partly dependent upon the gas velocity, hence the equilibrium saturation will be least nearest the well and increase outwardly from the well. There should be a halo of maximum saturation around the well outside of which not enough liquid had yet been deposited to reach equilibrium gas-liquid permeabilities. Inside this halo all additional condensates deposited should reach the well, and exterior to it all condensates would be retained in the sand pores. The quantities of condensates retained in the pressure sink can be large. In terms of the percentages of the original condensate reserves in the drainage area, it is theoretically likely to be larger for lean gas wells, and there is some field evidence that appears to support this view.

In a cycled reservoir there will be a third area with conditions different from those discussed in the preceding paragraphs. Near the injection wells, particularly if they are far from edge water, there will be areas in which the pressures will exceed original pressures, and in the early stages of the operation these areas may constitute nearly half the reservoir. Theoretically, there should be no condensation within the overpressured area; and, conversely, it is possible that liquids naturally occurring in the reservoir could be vaporized. Outside the overpressured areas, conditions should be much as previously described. The flow will be radial near the wells though more nearly unidirectional between the input and producing areas. However, by returning the residue gas to the reservoirs, the pressures will never be reduced so low at the producing wells as otherwise, and dry gas can be expected to reach them by the time the average static reservoir pressure has dropped as little as 5 per cent for lean gas and efficient operations, and as much as 20 per cent for the richer gases. But to cause the gas to flow from input to producing areas and to produce the wells at the desired rates will lead to the formation of pressure sinks around the producing wells, wherein pressures will be much below the average reservoir pressure.

From a consideration of what takes place in both cycled and depleted reservoirs, it would appear that the retrograde conditions remote from the producing wells more nearly resemble differential separation, whereas the conditions in the pressure sink more nearly resemble flash separation. Whether all the conditions affecting the condensation and retention of the condensable hydrocarbons are simulated in the usual retrograde tests must be determined by comparisons of laboratory with field data. The controlling well pressure, so far as retained condensates are concerned, should be at some pressure between bottom-hole flowing and static pressures. The laboratory retrograde curve assumes that all the condensates are retained in the reservoir, whereas varying proportions of the condensates do reach the well by liquid flow.

RETROGRADE TESTING

Two principles have been applied in testing for retrograde condensation. In "flash separation," pressures are reduced by expanding the size of the container, hence all the components originally in the gas are maintained in the apparatus in their initial proportions throughout the range of conditions to which the sample is subjected. In "differential separation" pressures are reduced by successively withdrawing gas from the container, which remains of constant size throughout the test. In both methods, the quantities of liquids that accumulate in the test cell are measured at a succession of pressures. As no important reduction in the temperature of the reservoir as a whole is expected, the tests are conducted usually only at the original sand-face temperature.

Two types of apparatus have been used for making retrograde tests. In the Sage and Lacey type, a sample of the effluent is taken in a bomb and transferred to the test cell. There are several variants of this type of apparatus, which are believed to produce essentially the same results under competent operation. The Parks'[2] type uses the same portable laboratory that is used to make G.P.M. tests at the well. A variant of this method is employed by the U. S. Bureau of

Mines.[3] To assure the taking of a true sample, the apparatus should be calibrated against a full-scale separator. In the Parks' type the results correspond to flash separation but in the Sage and Lacey cell tests can be made by either flash or differential separation.

The condensates deposited in the apparatus in the retrograde tests include dissolved gas and other light hydrocarbons that are not included in the liquid products obtained from plant operations or reported in G.P.M. well tests, therefore direct comparisons cannot be made; however, the condensates deposited in the reservoir itself are presumed to correspond to those deposited in the apparatus. The retrograde curve usually reported reflects both liquefaction of the heavier components, and solution of the lighter components of the effluent. As pressures decrease, more liquefaction takes place up to the retrograde point, but the liquids will hold decreasing percentages of gas in solution. In the normal region, still more gas comes out of solution and some of the liquids are revaporized. The heavier, less volatile hydrocarbons are more subject to condensation in the retrograde region and less subject to vaporization in the normal region.

Because pressures in the reservoir are reduced by withdrawal of gas, it has generally been thought that retrograde condensation would follow the differential separation, but there are also dissimilarities; in particular the condensation within the pressure sink around the flowing well may more nearly resemble a separator and follow flash separation. It appears that, theoretically, conditions within the reservoir will be a combination of the two principles of separation.

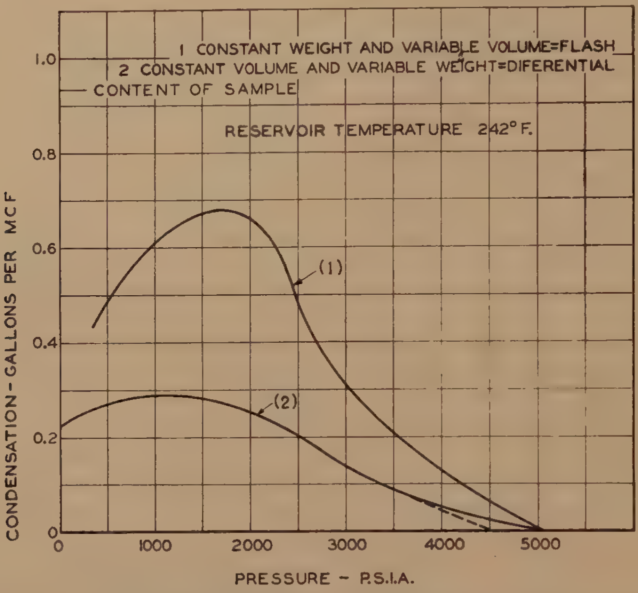


FIG. 1.—COMPARISON OF FLASH AND DIFFERENTIAL RETROGRADE CURVES FOR THE SAME GAS CONCAVE TYPES AND LARGE DIFFERENCES.

Retrograde curves are shown in Figs. 1 to 3, in which the liquids that have accumulated in the cell are plotted in G.P.M. against pressure. The G.P.M. scale is presumed to correspond to the cumulative losses that will have occurred by condensation in the reservoir at each successive pressure reduction. The place at which the cumulative losses reach the maximum is called the retrograde point. This reversal point separates the retrograde from the normal region. In the retrograde region, reduction of pressure causes condensation, whereas in the normal region reduction of pressure causes vaporization and some of the liquids deposited in the retrograde region are revaporized.

Figs. 1 and 2 show tests by both flash and differential separation on the same gases.

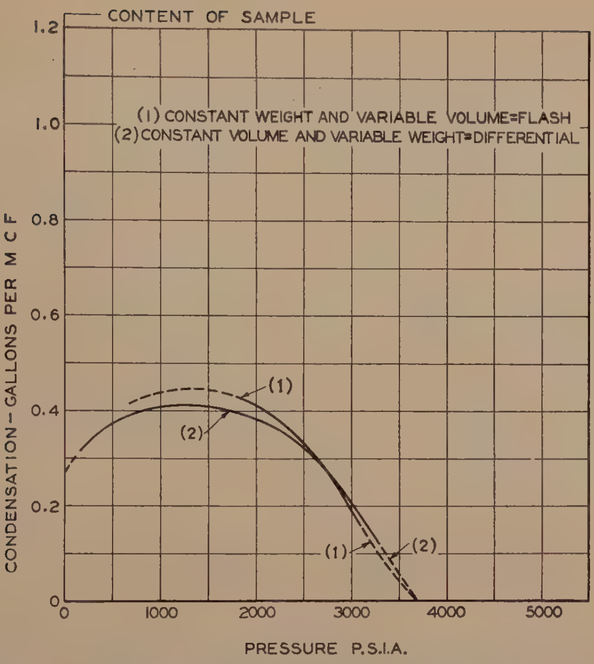


FIG. 2.—COMPARISON OF FLASH AND DIFFERENTIAL RETROGRADE CURVES FOR THE SAME GAS. CONVEX TYPES AND SMALL DIFFERENCES.

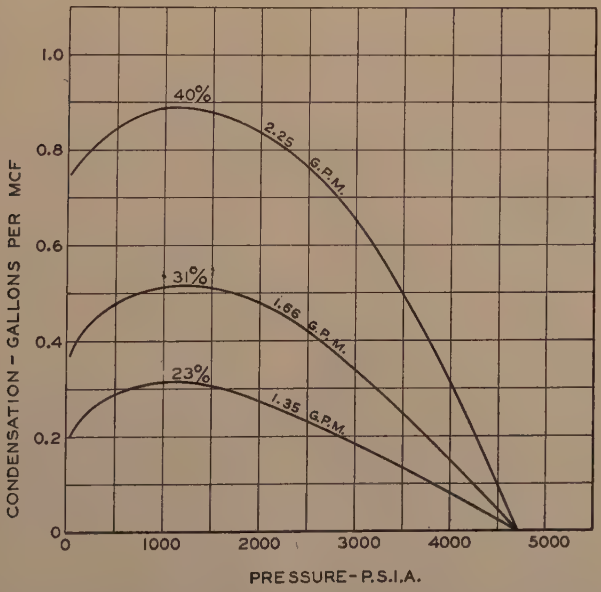


FIG. 3.—COMPARISON OF DIFFERENTIAL CURVES FOR THREE GASES OF DIFFERENT G.P.M. IN THE SAME RESERVOIR.

In all of the comparative tests known to the writer, more condensation has been shown by flash separation, though by varying amounts, Fig. 2 showing the least difference. Fig. 3 shows the average differential retrograde curves for three gases of different initial G.P.M. These three curves show how much more liquid is condensed from the richer gases both in quantity and in percentage of the initial content.

Most of the retrograde curves known to the writer are convex, as shown in Figs. 2 and 3, but a few have a concavity on the retrograde leg as shown in Fig. 1. The writer suspects that the correct type is the convex curve and that the concave type may be due to a sample secured during a transition period in the well that does not represent equilibrium conditions within the reservoir.

Methods for Sampling and Testing Effluent from Gas-condensate Wells

Efforts to secure bottom-hole samples from gas-condensate wells have not been successful, therefore it has been necessary to sample the effluent at the top of the well. As both pressures and temperatures are reduced when the gas reaches the surface, some of the vapors will have condensed and the effluent will consist of a liquid and a gas phase.

So far, two methods for sampling the effluent have been employed. In one, the whole stream is passed through a full-scale separator, and in the other a small part of the stream is diverted. Another method that, to the writer's knowledge, has not yet been used would be to bring the whole stream to single-phase flow by heat or by a combination of heat and increased pressure, whereupon, a representative sample could be diverted from the stream.

In the first method the usual full-scale separator is used. Under the decreased pressures and temperatures some of the vapors condense and are retained in the separator while the uncondensed part of the effluent passes out as overhead gas. By gauging the liquid and metering the gas, the proportions of the two can be determined and aliquot parts of the liquid and gas can be combined for a sample, or tests can be made independently of the liquid and gas phases. By this method a correct sample of the effluent can be secured.

The ratio of liquefiable to gaseous components can be expressed either as G.P.M. (gallons per thousand cubic feet), or barrels per million cubic feet, or cubic feet of gas per barrel of liquid (G.O.R.). The gas and liquids are usually expressed in standard units; i.e., at 14.7 lb. per sq. in abs. and 60°F. The liquids usually reported are pentanes and heavier hydrocarbons, though sometimes butanes plus are reported.

On some properties, all the wells are operated on full-scale separators, and only the liquids recovered from the separators are reported as production, the overhead gas sometimes going into pipe lines to gasoline plants or to distant markets. Under such conditions, condensation is not complete in the separator, and the proportion of condensation that takes place is influenced to an important extent by the pressure and temperature conditions in the separator, particularly the temperature. Separator temperatures are influenced by weather conditions and still more by flow rates. Whether separation is made in one or multiple stages is also important, as is the manner of stabilizing the liquid. For these several reasons, separator production alone does not bear any constant relationship with the total content in the effluent and it must be supplemented by tests on the overhead gas to get the full and correct G.P.M.

The probe method of sampling by diverting a part of the stream into a small-scale separator has been described by J. M. Flaitz and A. S. Parks.[2] A small tip is inserted into the stream and a portion of the effluent is conducted through a copper pipe into a portable laboratory, where the gas is passed through a small-scale separator held at 1200 lb. per sq. in. gauge pressure and 70°F. temperature. The condensates left in the separator are measured and tested for A.P.I. gravity and for solution gas and shrinkage. The separator gas is passed through a charcoal absorber and the residue gas is metered. The gas gravity is determined on the separator gas before it enters the charcoal absorber. The G.P.M. usually reported consists especially of pentanes and heavier.

It is generally agreed that, properly operated, the portable laboratories will give determinations as accurately as are needed for usual field purposes, but it has been found by experience that the method of sampling cannot be relied upon to get aliquot parts of the gas and liquid phases from the effluent. During the past two years, the National Gas Association has conducted an elaborate program for improving the sampling technique, under the supervision of G. G. Brown, Donald Katz and A. S. Parks,[5] which has disclosed the sources of inaccuracies and has reduced their magnitudes but has not yet resulted in assurance that accurate sampling can be done, short of calibrating against a full-scale separator. These tests have disclosed that large inaccuracies could have occurred in the sampling methods that have been commonly used in past years.

SAMPLING THE RESERVOIR

The problem of sampling is not solved merely by accurately sampling the effluent itself for it must be known whether the effluent is representative of the gas immediately around the well and whether the gas varies in composition within the reservoir. Sampling is done first to determine the original characteristics of the gas in the reservoir and later to determine from time to time what changes have occurred in the effluent.

To determine the original characteristics of the gas, it is, of course, desirable that samples be secured early in the life of the field though it is believed that by extrapolating backward reasonably close estimates can sometimes be made of the original content of the gas, and whether the gas was at dew point under original pressure. More than one well in each reservoir should be sampled, to determine whether there are important variations in the gas, particularly in a reservoir with an oil rim.

The changes in the composition of the effluent of a well that can take place include condensation and retention of liquids in the reservoir in the retrograde region of pressures, and, finally, the revaporization and removal of some of the condensates in the region of normal pressures; changes in content due to drawing in gas of a different original composition from a more distant part of the reservoir; invasion of injected dry gas and occasionally the invasion of gas from another sand by channeling behind the pipe or by leaky well equipment.

Effects of Changing Flow Rates

Differences in the composition of the effluent can be areal and persistent or they can occur locally within the pressure sink and be transient and partly reversable. There are reasons to believe that changing flow rates may be nearly as important a cause of erratic G.P.M. records as faulty sampling, or laboratory methods.

A change in flow rate will change both the retrograde conditions and the equilibrium gas-liquid saturation in the pressure sink. An increase in the flow rate will reduce pressures, which will promote condensation in the retrograde region, but at the same time it will increase gas velocities and decrease the liquid saturation necessary for liquid flow, hence the two effects are opposite. The long-time effect of an increased flow rate is to increase the area of the pressure sink and to increase the severity of retrograde conditions, but the short-time effect may be to unload from the pressure sink some of the liquids that previously had been deposited in it. When flow rates are reduced, there will be less condensation and more retention of liquids and the pressure sink will load up again. The loading and unloading of the pressure sink is a transient adjustment period but it may take several days or even many weeks for a new equilibrium to be reached. It can be reasoned that adjustment to a new equilibrium saturation will be comparatively rapid early in the life of a well when the saturated portion of the pressure sink is comparatively small, and that it will take longer and longer for readjustment as the saturated area enlarges. By the same reasoning, it could be expected that it will take longer for readjustment for a rich gas than for a lean gas.

The flow rate also affects the sampling of the effluent. At low vertical velocities in the well, the gas will lift the liquids in slugs, and at still lower velocities the gas may for a while merely boil up through liquid in the bottom of the well. It has also been found that a high velocity is needed in the flow pipe from which a sample is being diverted to get nearly aliquot parts of the gas and liquid phases by the probe method. As some wells are regularly produced at rates too low for good sampling, the rates are increased when the wells are to be sampled, and there is evidence that often sampling is done before a new equilibrium is reached.

Evidence on the effects of changing flow rates and of the short and long-time effects are shown in Figs. 4 and 5. The data for these graphs were obtained from a field where each well was being produced through a full-scale separator. The G.P.M. was determined by gauging the separator liquid, metering the gas and determining the contents of the separator gas by charcoal absorption.

The data from which the curves in Fig. 4 were derived were obtained in connection with back-pressure tests on the wells. After each change in flow rate, the well was allowed to stabilize at least 48 hr. The arrows indicate the order of the tests. The four records are representative of the results obtained in testing a number of wells. Though generally the wells showed lower G.P.M. at high flow rates and higher G.P.M. at low flow rates, there is much erraticism, and it is obvious how deceptive changing flow rates can make G.P.M. tests. In this field 48 hr. was not sufficient to establish new equilibriums. However, others who have tested wells in other fields report no significant change in G.P.M. at varying flow rates.

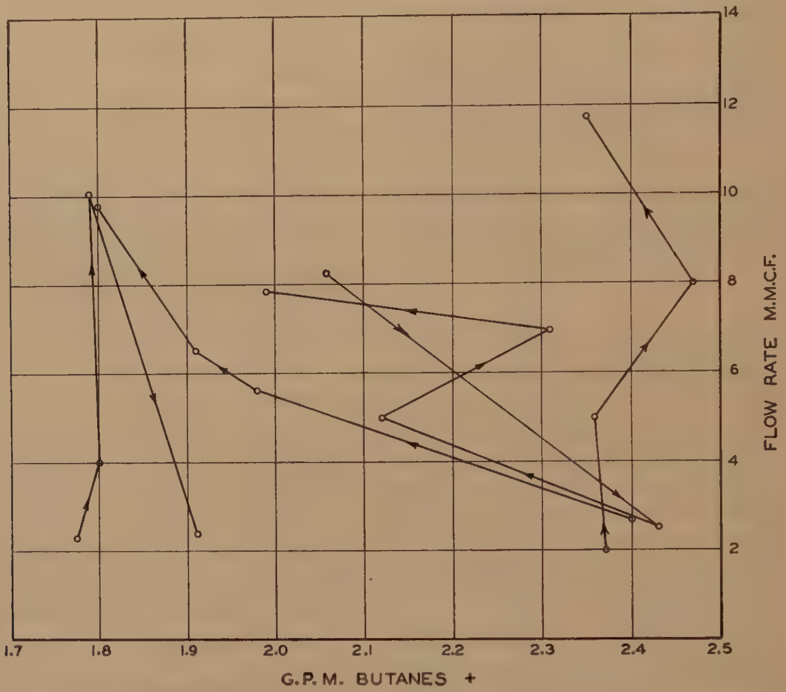


FIG. 4.—VARIATIONS IN G.P.M. FOR FOUR WELLS AT DIFFERENT FLOW RATES. SHORT TIME EFFECTS.

The long-term effects are shown in the records of two wells in Fig. 5. Each well shows the general loss in G.P.M. that is to be expected from pressure losses. Superimposed on this trend; the effects of changed flow rates are clearly evident though the data do not permit making quantitative estimates. In the upper graph, a drop in flow rate from 3100 to 1700 M cu. ft. corresponds to a marked increase of G.P.M. over the previous trend. In the lower graph, a drop in the flow rate from 7900 to 3,000 M cu. ft. corresponds to an actual increase from 2.85 to 3.90 G.P M. This was followed by an increase in flow rate, which coincides with a decrease in G.P.M.

As high flow rates reduces the current G.P.M. to an important degree, consideration should be given to the over-all effect on condensate recovery during the life of the reservoir. It can be reasoned that in a depleting operation the wells will have to go through all the stages of pressure reduction past the retrograde pressure to final commercial exhaustion in the normal region, and that by high flow rates the well merely goes through these stages sooner, and that the final results will be the same. In a cycling operation, low flow rates will cause less pressure reduction at the well by the time dry gas reaches it, hence there is more reason to believe that low flow rates might be beneficial. The writer has no field evidence to support an opinion under either method of operation.

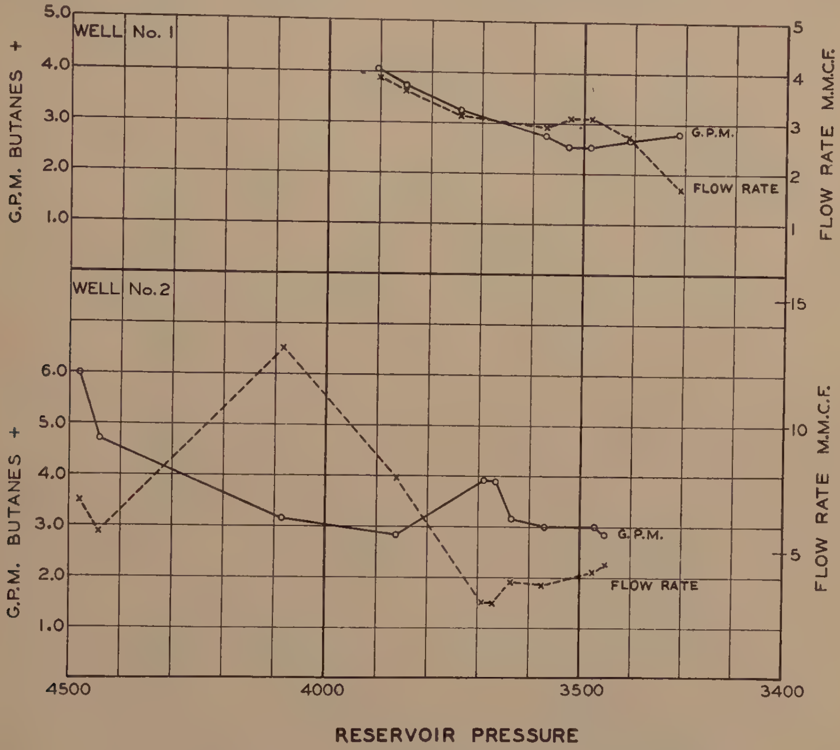


Fig. 5.—Long time effect on G.P.M. by changing flow rates.

Interpretation of Retrograde Test Data

To compare field data with the laboratory data, it is necessary that they represent the same composition and that both show either cumulative or instantaneous G.P.M. McAllister[6] has shown what proportion of the condensates in the test apparatus can consist of hydrocarbons lighter than pentane. Furthermore, the well or plant records usually are a series of instantaneous G.P.M. or rates, whereas the liquids deposited in the cell show the cumulative loss or, when converted into recovered G.P.M., show the average G.P.M. up to each stage in pressure reduction.

Fig. 6 is based upon McAllister's curve for n-pentanes plus, shown in his Fig. 2, which is the cumulative retrograde condensation by differential liberation of a gas sample from a California field. Curve *A*, Fig. 6, shows McAllister's curve converted to G.P.M., the cumulative loss in n-pentanes plus being shown above curve *A* and the cumulative recovery below. Curve *B* shows the instantaneous G.P.M. at successive pressures which was computed from Curve *A*. Curve *B* corresponds to the usual record of G.P.M. well tests plotted against pressure. At 2500 lb. per sq. in., curve *A* shows that the average content of the gas so far produced had been 2.62 G.P.M., whereas, curve *B* shows that the gas being produced currently had 1.72 G.P.M.

Curve *B* conveys quite a different impression than the usual cumulative retrograde curve. The decline in G.P.M. is much faster in the retrograde region and the pickup in the normal region is seen to be much larger, and at low pressure the gas will be richer than it was initially. This indicates that much pentane and some of the heavier hydrocarbons will be volatilized and recovered at low pressures, and because of the increasing richness of the gas, the wells may profitably be produced to relatively low pressures. The condensates recovered in the normal region can be expected to be nearer natural gasoline in composition.

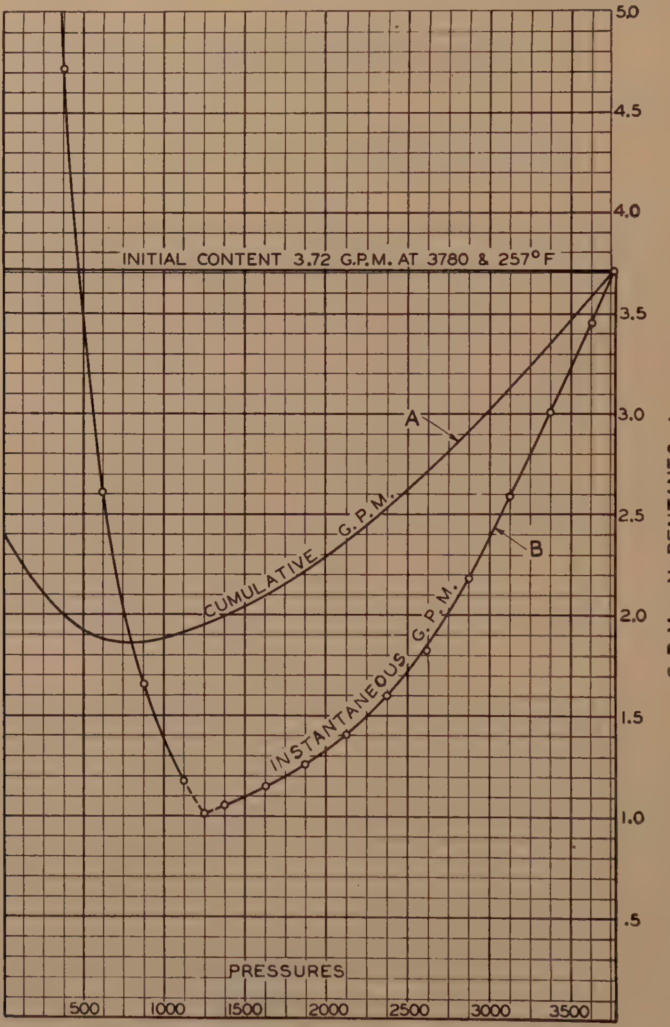


FIG. 6.—CUMULATIVE AND INSTANTANEOUS G.P.M. RETROGRADE CURVES CALCULATED FROM MCALLISTER'S FIGURE 2.

The G.P.M. at low pressures will be greatly influenced by reservoir temperatures, and the gas should become richest in the deep sands with higher temperatures. The writer has no field data showing whether or not G.P.M. does increase in the manner predicted by the rate curves computed from retrograde tests

In Fig. 7, the two legs of curve *B* are plotted on logarithmic paper, the retrograde leg being plotted against reduced pressures and the normal leg against pressure gains, constants being added to both to straighten them out. Both reach approximately the same G.P.M. near 1250 lb. per sq. in., which may be taken as the point of convergence. It will be noted elsewhere that four G.P.M. curves from field data also plot as straight lines on logarithmic paper. However, not all rate curves computed from retrograde curves can be plotted logarithmically, this being notably true with respect to the rate curves derived from retrograde curves that show concavity in the retrograde leg as shown in Fig. 1. It must be left to the physicist to determine whether the rate curve is always basically logarithmic, and whether a lack of fit is evidence of erroneous data or a sample not in equilibrium.

The two legs of curve *B*, Fig. 6, are shown as probably meeting at an acute angle at a higher pressure than the conventional retrograde point shown on the cumulative curve *A*. Plots made similarly from some other retrograde curves indicate the same thing whereas others show a rather sharp curvature. It would appear that the transition from the retrograde to the normal region may be through a point and that it occurs at a higher pressure than the retrograde point taken from the cumulative curve.

Should further information prove that retrograde condensation follows a definite mathematical equation that is graphically expressed as a straight line on logarithmic paper, it will provide a useful tool for field and laboratory use.

Interpretation of G.P.M. Tests

In the Gulf Coast area, G.P.M. tests usually are made on the effluent of each well every three months. The samples usually are obtained by the probe method and analyses are made in portable laboratories as previously described. These tests are for the purpose of determining the changes in content and to detect the entry of dry gas into the well. Since a change in content can result from either retrograde condensation, from the invasion of dry gas, or from errors in sampling and in analysis, it is highly desirable to be able to tell when dry gas reaches the well and what portion of the effluent is dry gas.

Study of the test data show that they provide three indicators for dry gas, which can be used to give at least approximate estimates on the dry gas dilution and could be made still more reliable by improvements in sampling and testing. The three indicators are: (1) the G.P.M. of the separator gas obtained by charcoal test, (2) the gravity of the liquids deposited in the separator, (3) the gravity of the separator gas. The first is the most usable and the last is the least usable indicator.

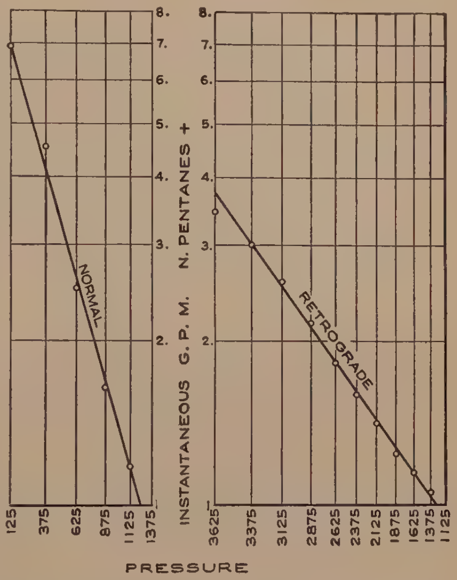


Fig. 7.—Instantaneous G.P.M. retrograde curve from Figure 4 plotted logarithmically.

In Fig. 8 are shown the average records of 19 wells over a period of 3 years in the La Gloria field, Texas. Curves are shown for the total G.P.M., the A.P.I. gravity of the separator liquid and the G.P.M. of the separator gas. Records of these wells were selected because it was evident that dry gas could not yet have reached any of them. The 19 records only partly average out the erraticisms of sampling and laboratory analysis.

The curves show quite plainly that whereas there has been a notable decline in the total G.P.M. of pentanes plus there has been no corresponding downward trend in either the charcoal G.P.M. or the gravity of the separator liquid. The two lower curves show less erraticism than does the total G.P.M. curve. Data from the Stratton-Agua Dulce field show similar results, but not so convincingly because the data are more erratic. There is some evidence that the liquid gravity and the separator gas G.P.M. may pass over a slight maximum but this could be caused by inaccuracies in the data.

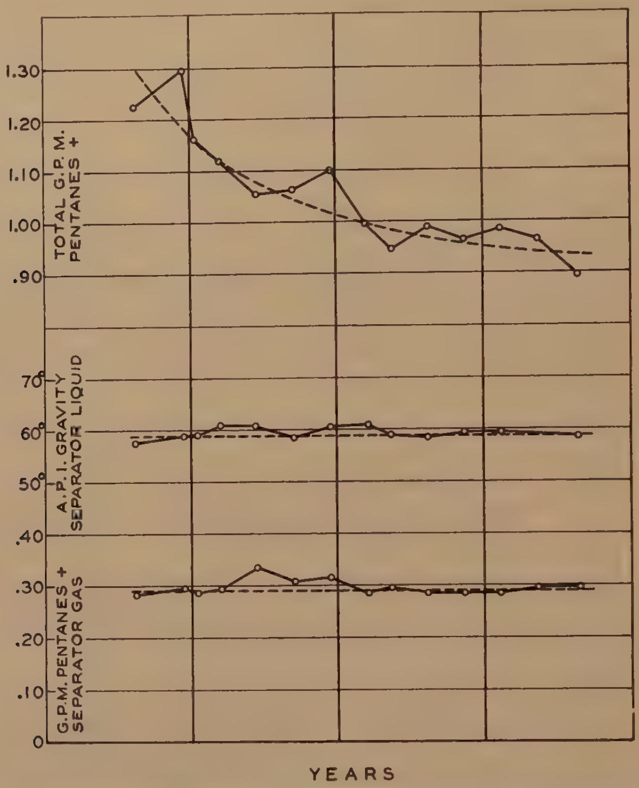


FIG. 8.—PLOT OF AVERAGE G.P.M. DATA FOR NINETEEN WELLS IN THE LA GLORIA FIELD, TEXAS.

Figs. 9 and 10 are the records of two wells in different reservoirs in the La Gloria field. The entry of dry gas into these two wells is shown by the declines in separator gas G.P.M. and separator liquid gravity. That dry gas has reached the wells is confirmed by the calculated area filled by injected residue gas. The two records show how unreliable an indicator is the total G.P.M. From it alone, it cannot be told whether the loss in G.P.M. is due to retrograde condensation, to dilution, or to some other cause.

The theoretical basis for the use of the content of the separator gas as an indicator is that the effluent is subjected in the miniature test separator to a reduction in pressure to 1200 lb. per sq. in. gauge, and in temperature to 70°F., which results in retrograde conditions far more severe than the effluent had been subjected to before it left the reservoir or in the flow pipe; hence it could not be expected that any of the material that could leave the test separator in gas phase could be condensed underground. Also, such material, being in gas phase, would be little affected by changing flow rates or by sampling errors. It would, therefore, appear that if the miniature test separators are kept uniformly at the same pressure and temperature in all tests and the charcoal determinations are made accurately, the separator gas G.P.M. should be constant until dry gas invaded the well. After dry gas reached the well, the separator gas G.P.M. should decline nearly in proportion to the percentage of dry gas in the effluent provided the injected residue gas had been completely stripped of its pentanes plus. However, allowances must be made for the lighter hydrocarbons that will be revaporized by the dry gas from the liquids that had previously been condensed in the reservoir. For this reason this indicator can be expected to underestimate the percentage of dilution.

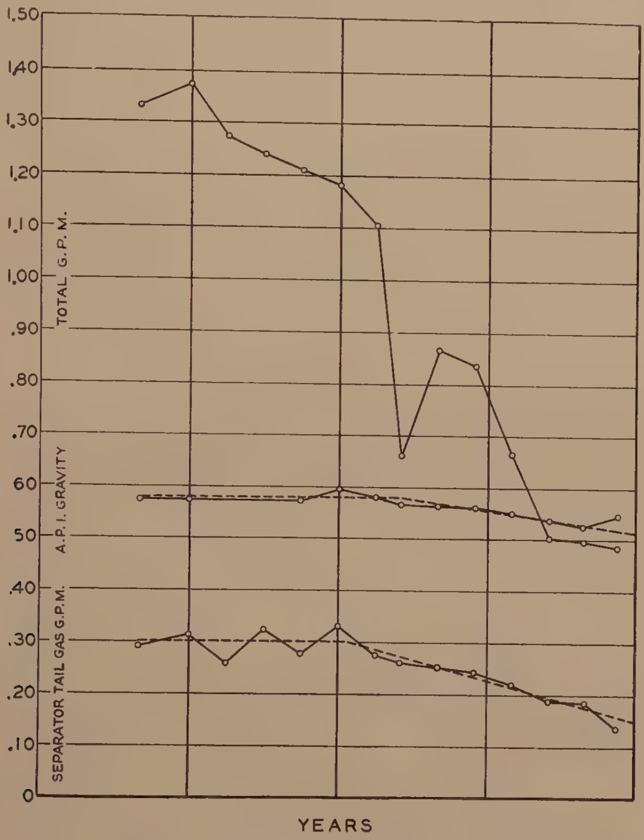


FIG. 9.—PLOT OF G.P.M. RECORD OF WELL INVADED BY DRY GAS.

The reason why the A.P.I. gravity of the separator liquid remains constant until dry gas invades the well is not clear. The theory is that the heavier hydrocarbons condense selectively and progressively in the reservoir as pressures are reduced, so that the gravity of the condensates retained in the sand is distinctly heavier than the produced condensates. When dry gas reaches the well, it carries with it revaporized material of heavier composition, which results in the decrease in A.P.I. gravity of the produced condensates. Conversely, the previous condensation and retention in the reservoir of heavier material before dry gas reaches the well should have caused ascending A.P.I. gravity of the produced liquids, and this is true with respect to wells in reservoirs that are not being cycled. In cycled reservoirs, wells remote from the input area also show some evidence of producing progressively lighter condensates before the entry of dry gas, but wells closer to the input wells show some tendency to produce progressively heavier liquids even before dry gas reaches them. The constant A.P.I. gravity of the separator liquid before the invasion of dry gas may be due to condensation.

Fig. 11 is a plot of the separator gas G.P.M. against the gravity of the separator liquid, each point representing a test on a well in the La Gloria field. The data indicate a general trend relationship between the two factors and data from the Stratton-Agua Dulce field show a similar trend. As soon as there are sufficient data to construct such a curve for a field, the curve can be used to check the test data for erraticism and to make closer estimates of dilution

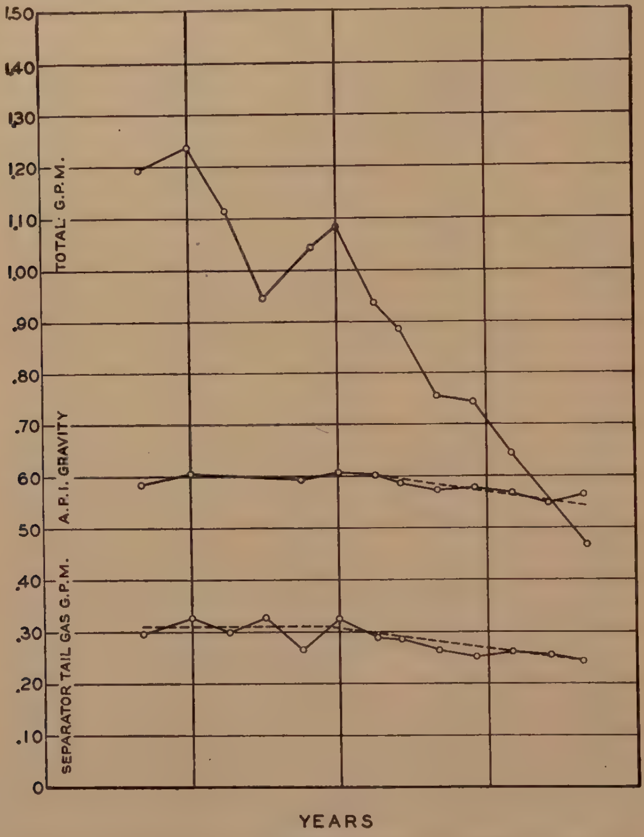


FIG. 10.—PLOT OF G.P.M. RECORD OF WELL INVADED BY DRY GAS.

The reduction in the specific gravity of the gas as it is produced at the well or as it is recovered from the test separator could be used as an indicator, but as the gravity of the injected residue gas is subject to changing plant extraction, this would be a reliable indicator only when the plant extractions had not been changed to an important degree. During the war years, most plants increased butane extraction, and some plants extracted much of the propane. Complete hydrocarbon analysis would also be subject to changes in plant operations as well as to changing flow rates and to sampling errors, therefore it does not appear to be more efficient than the usual G.P.M. test data for detecting invasion of dry gas.

DRYING OF WELLS

Experience shows that wells do not change abruptly from all wet to all dry gas; the change is gradual, and usually many months pass before the gas becomes so diluted that it cannot be processed economically. It is believed that dry gas almost completely dis-

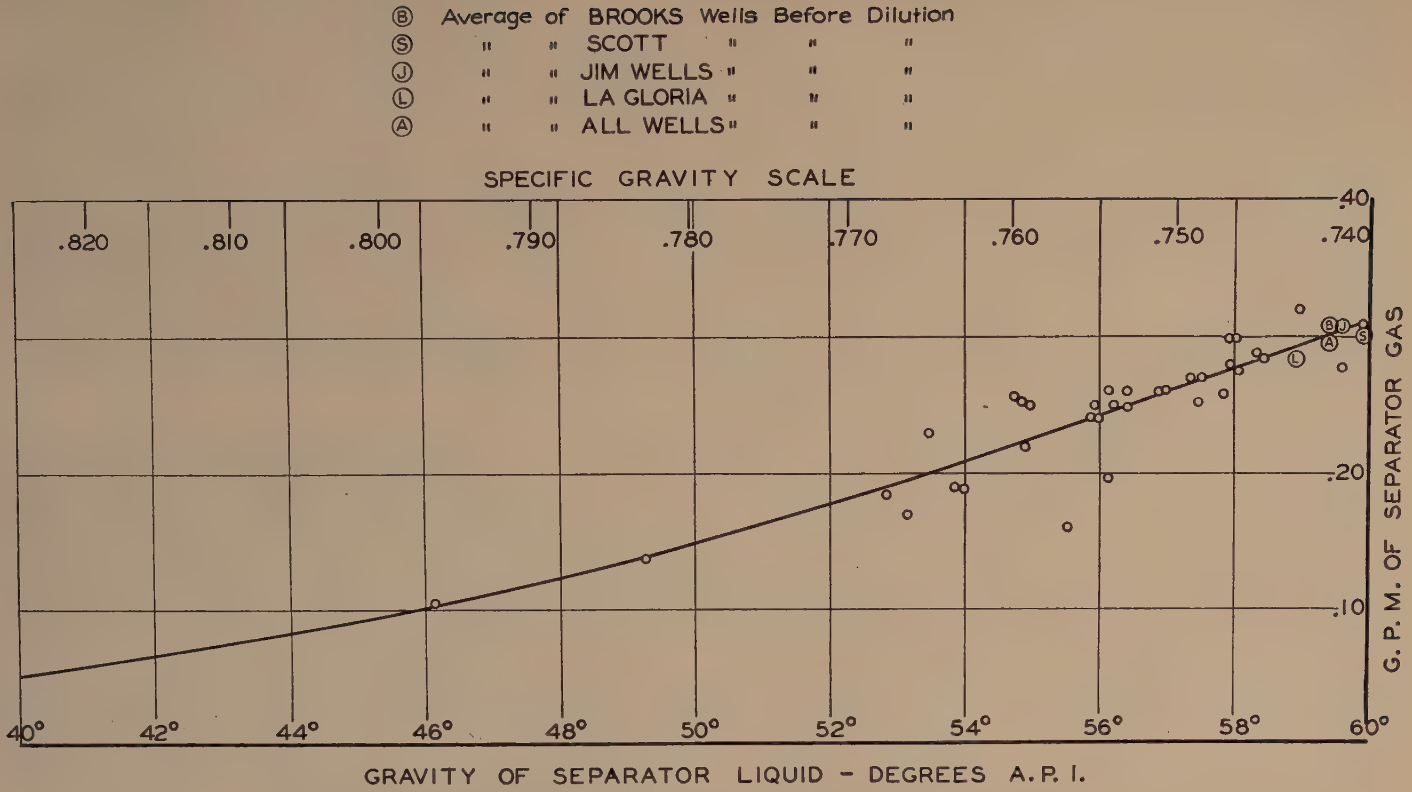


FIG. 11.—RELATION BETWEEN SEPARATOR GAS G.P.M. AND SEPARATOR LIQUID GRAVITY.

places wet gas from homogeneous sand and that there is very little mixing of the two, however, as sands are never homogeneous, wet gas can be pocketed in sand-body irregularities and there can be parallel flows at different velocities through strata or areas of differing permeabilities, as described by Hurst and Everdingen.[6] The only field evidence available to the writer on this subject is inconclusive. An injection well in the Stratton Agua Dulce field when later put on production had 0.15 G.P.M. in the back flow of the injected residue gas. Presumably all the pentanes plus had been extracted prior to injection, therefore it is thought that some pentanes plus had been picked up in the reservoir near the injection well. There appears to be two possible explanations: (1) that some of the original wet gas had been pocketed in sand irregularities; or (2) that at time of discovery some liquids were present in the sand, which had been revaporized in the overpressured area around the injection well.

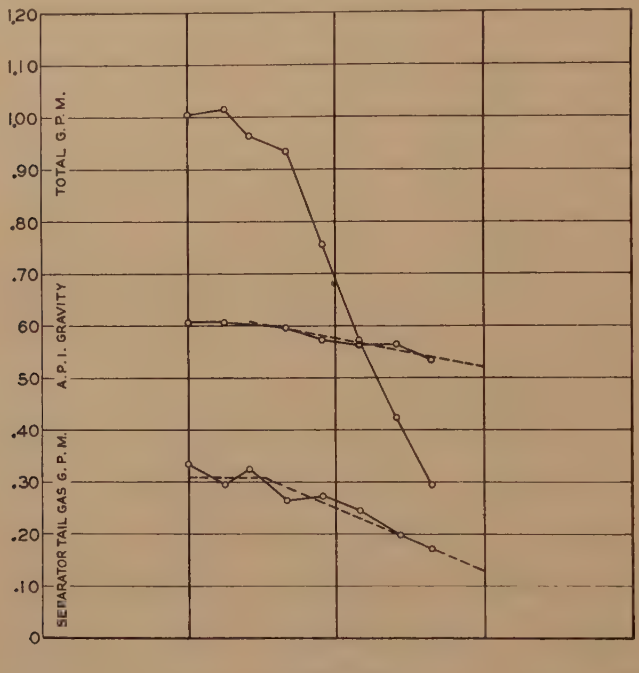


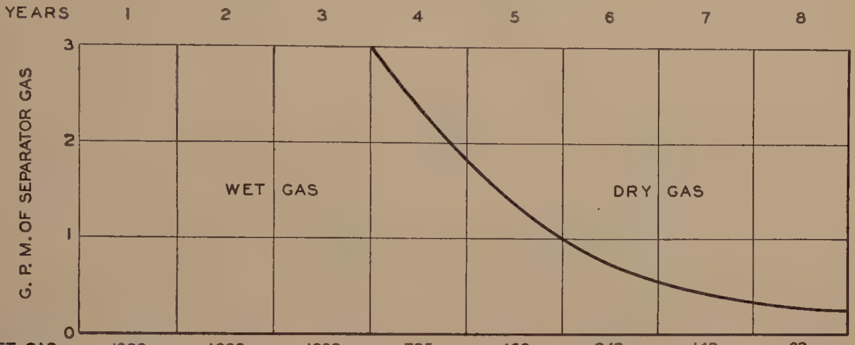
FIG. 12.—PLOT OF G.P.M. RECORD OF INVADED WELL NEAR INJECTION WELLS.

But even if the sand body were fully homogeneous, the dry gas would enter the producing well first as an infinitesimal part of the flow, which would then progressively increase in the manner disclosed in studies with the electric model.[6] Theoretically, a pattern consisting of one input and one production well could sweep out a pool in course of infinite time and if carried to infinite dilution. A well at the far end of a pattern theoretically will approach 100 per cent dryness asymtotically, though intermediate wells can dry up quickly and completely because the dry gas will be drawn past them by the outlying wells.

Fig. 12 shows the record of a well close to the injection well whereas Figs. 9 and 10 show records of more remote wells. The increases in dilution in these three wells are shown as straight lines against time, but the electrical model and theory both indicate that the relationship will become curvilinear.

This is shown in the hypothetical graph Fig. 13, which illustrates a method for estimating the quantities of dry gas that must be produced from a well, the separator gas G.P.M.

being taken as the measure of dilution. The percentage dilution finally reached and the total percentage of residue gas that will be recycled through the sand will depend mostly on economic factors. Operators in the Gulf Coast area generally consider that it is uneconomical to cycle gas with less than 0.3 G.P.M. If by the time dilution starts, the content had dropped to 0.6 G.P.M., production of the well would cease at about 50 per cent dilution, but if the content were 3.0 G.P.M., 90 per cent diluted gas could be processed and reinjected. From Fig. 13 it can be estimated that the 0.6 G.P.M. well would recycle a total of about 10 per cent residue gas and the 3.0 G.P.M. well would recycle about 50 per cent residue gas before the economic limits were reached; that is 10 to 50 per cent of the gas would have to be passed through the sand twice to reach 0.3 G.P.M.



WET GAS	1000	1000	1000	785	450	243	143	93
DRY GAS	0	0	0	215	550	757	857	907
CUM. WET GAS	1000	2000	3000	3785	4235	4478	4621	4714
CUM. DRY GAS	0	0	0	215	765	1522	2379	3286
CUM. TOTAL	1000	2000	3000	4000	5000	6000	7000	8000
CUM. RATIO	100	100	100	105.7	118.1	134.0	151.4	169.5

$$\text{CUM. RATIO} = \frac{\text{CUMULATIVE TOTAL GAS PRODUCED}}{\text{CUMULATIVE WET - GAS PRODUCED}}$$

FIG. 13.—CHART ILLUSTRATING METHOD FOR ESTIMATING DRY GAS TO BE RECYCLED.

REVAPORIZATION OF CONDENSATES

The revaporization of liquids that had been condensed and retained in the reservoir can occur either by contact with injected dry gas, usually in the retrograde region, or by normal vaporization at pressures below the retrograde pressure. It has been shown that the condensates deposited in the reservoir by retrograde condensation will consist largely of the heaviest hydrocarbons with hydrocarbon gases in solution. The lighter hydrocarbons can be expected to be volatilized readily in either region, but not much of the heavier components can be expected to be vaporized in the normal region.

The dry gas can be expected to revaporize selectively the more volatile hydrocarbons, therefore the first dry gas to reach the well should carry comparatively light hydrocarbon vapors, but they should become increasingly heavy with time, and this in part causes the progressive reductions in A.P.I. gravity of the pentanes plus shown in Figs. 9 to 12. In the La Gloria field, the heaviest hydrocarbons in appreciable quantities in the undiluted effluent is a liquid of 36.2° A.P.I., or 0.8436 Sp. Gr. with an initial boiling point of 463°F. and evaporation point of 647°F. Extrapolation of the trend relationship between separator gas G.P.M. and gravity of separator liquid shown in Fig. 11 indicates that the separator liquid would reach this gravity at 0.05 G.P.M., which indicates a dilution of approximately 0.83⅓ per cent. Fig. 11 can be used as a basis for calculating the approximate gravity of the revaporized liquids contained in the effluent at any stage of dilution.

As revaporization in the retrograde region is so much more effective than in the normal region, it cannot be expected that there will be important normal revaporization in any part of the reservoir that has been swept by dry gas, but there can be expected some recovery of solution gas and of pocketed wet gas when pressures are finally reduced below the retrograde point. In the areas not swept by the dry gas, normal vaporization can be expected to go on as indicated in Figs. 4 and 5, and at low pressures the produced gas is likely to become richer than it was originally.

It is doubtful whether there is much mixing of wet and dry gas until the gases reach the vicinity of the well, as the two fluids will mostly travel independently through the reservoir. In the parts of the sand body not yet invaded by dry gas, retrograde condensation can go on, whereas in adjacent parts retrograde revaporization can take place. The progressive decline in total G.P.M. during the dilution period will be caused partly by continued retrograde condensation in the wet gas areas as well as from increasing invasion of dry gas.

The gas injected into the reservoir is usually residue gas from which pentanes plus and varying proportions of propane and the butanes have been removed. Often the residue is from the commingled production from several reservoirs. The residue gas has the capacity to revaporize the retained condensates both in the normal and in the retrograde region, but in the retrograde region it cannot be expected to have as much capacity to revaporize condensates as the original gas, for Olds, Sage and Lacey[1] have shown that the removal of the intermediate hydrocarbons such as propane and butane, can reduce that capacity. Furthermore, the injected residue gas will reach the well at a pressure less than the original, which will still further reduce its vapor-carrying capacity. Because the retained condensates will be spread over the enormous surfaces of the sand grains, it appears probable that the gas will become vapor-saturated by the time it reaches the producing well, but because of the other reasons, it could be expected that it would require the recycling through the sand of more residue gas than the quantity of wet gas from which the condensates were derived to revaporize all the retained condensates. Under commercial conditions, it has been shown that the residue gas to be recycled will probably range from 10 to 50 per cent of the wet gas produced, and it can be expected that recovery by revaporization of dry gas in the retrograde region will be less than 10 to 50 per cent.

Comparisons of Field with Laboratory Retrograde Losses

The industry has proceeded necessarily on the assumption that retrograde laboratory tests were analogous to underground conditions, and that such tests would provide data reliable enough to be used in predicting losses to be expected in the reservoir. It has been realized that the effects of the enormous surface areas of the reservoir pores were not duplicated in the laboratory, but it has been thought that agitation in the cell would give the same results. It has also been realized that perhaps the cells did not simulate some of the other conditions in the reservoir that might be important. It has been obvious that only from comparison with field data could it be known how valid was the assumption of similarity between laboratory and reservoir conditions.

From the preceding discussions, the difficulties in checking laboratory against field data are apparent. To make valid comparisons, it must be assured that the two sets of data apply to the same gas and to the same conditions. With respect to the determination of the retrograde behavior of the gas in the laboratory, the following are the considerations:

1. That the tests are made on representative reservoir samples at reservoir temperatures.
2. Whether differential or flash separation should be used or something in between.
3. The test data should represent the same hydrocarbon composition as the field data.
4. The cumulative losses should be converted to rate losses.

With respect to the field tests of the gas from the producing wells, the following are the considerations:

1. Reliable sampling of the wells and of the reservoir.
2. The samples must be from uncontaminated wells, which originally had the same composition as the test samples.
3. The samples must be accurately analyzed.
4. It must be determined whether comparison is to be made at flowing or

bottom-hole pressures, or at some intermediate pressure.

The writer so far has not had access to data that meet these requirements within reasonable limits. The only checks that can be made are whether the laboratory and field data are within reconcilable coincidence.

Individual well tests have been found to be too unreliable for use in a reservoir or project investigation, hence it has been necessary to use averages, on the assumption that the errors are random and that for a number of wells they will be nearly compensating. This assumption can be checked by comparisons with the plant output. The weighted average G.P.M. from well tests is obtained by multiplying the G.P.M. for each well by that well's monthly gas production, and the totals should equal the plant's production. However, adjustments must be made where the plant production includes propane and butanes and the well test data do not.

Fig. 14 compares the weighted averages obtained in the two ways in the La Gloria field, both showing pentanes plus. From these records it is evident that there is a persistent difference in trend between the two and that the well tests showed more than the true content during the first few months of operation and less in later months. However, the smoothed curves are never more than 5 per cent apart. The graphs show that all the well tests deviate in one direction or the other at certain test periods. There is some evidence that well tests show higher content in winter than in summer. The plant production record appears to fit a logarithmic curve.

In the Stratton-Agua Dulce field, the records of three plants show less consistent deviations. The comparable parts of the records show the data given in Table 1.

TABLE 1.—*Records of Three Plants, Stratton-Agua Dulce Field*

Plant	Avg. Well G.P.M.	Plant G.P.M.	Difference, Per Cent
Wardner	0.828	0.870	+5
Coastal	0.790	0.812	+3
Gulf Plains	0.831	0.815	−2
Averages	0.816	0.832	+2

The plant record itself can be used as the average where it has been operating under reasonably uniform conditions; that is, taking gas from the same wells at nearly the same rates while the plant meanwhile extracts the same products. A 21-months period reasonably well satisfies these requirements for the La Gloria plant. In the early months of operations one well that produced some oil caused the high content shown in Fig. 14, but after it was taken off production, field and plant operations were nearly uniform until dry gas began to invade some of the wells in important quantities. The smaller irregularities are caused principally by minor changes in plant operation and well productions. Unfortunately, no retrograde tests have been made on the gas from the La Gloria field to compare with this record.

In Fig. 15 are shown the smoothed averaged G.P.M. curves for three groups of wells in the Stratton-Agua Dulce field. The average G.P.M. is plotted against time, but as each group of wells was produced at nearly uniform rates, the time scale is nearly proportional to the pressure loss. All three records plot as straight lines on logarithmic paper by adding constants to the time scale. Curve *A* is the average of seven shallow wells in sands that were being cycled. Curve *B* is the average of 26 deeper wells in sands that were being cycled, and curve *C* is the average of six wells of nearly the same depth as for curve *B* but in sands that were not being cycled. The more significant facts respecting the three groups of wells are given in Table 2.

TABLE 2.—*Three Groups of Wells in Stratton-Agua Dulce Field*

Averages	A	B	C
Initial pressures, lb. per sq. in.	2,250	3,030	3,150
Initial G.P.M.	0.62	1.05	1.04
Loss in G.P.M., in 4 years	0.31	0.36	0.28
Percentage loss in 4 years	50	34.5	27
Loss in static bottom-hole pressure, lb. per sq. in.	170	410	500
Loss to flowing bottom-hole pressure, lb. per sq. in.	280	500	670

Retrograde tests by flash separation were made on wells that fairly well represented the shallow and deeper groups of wells. The shallower wells showed a maximum average

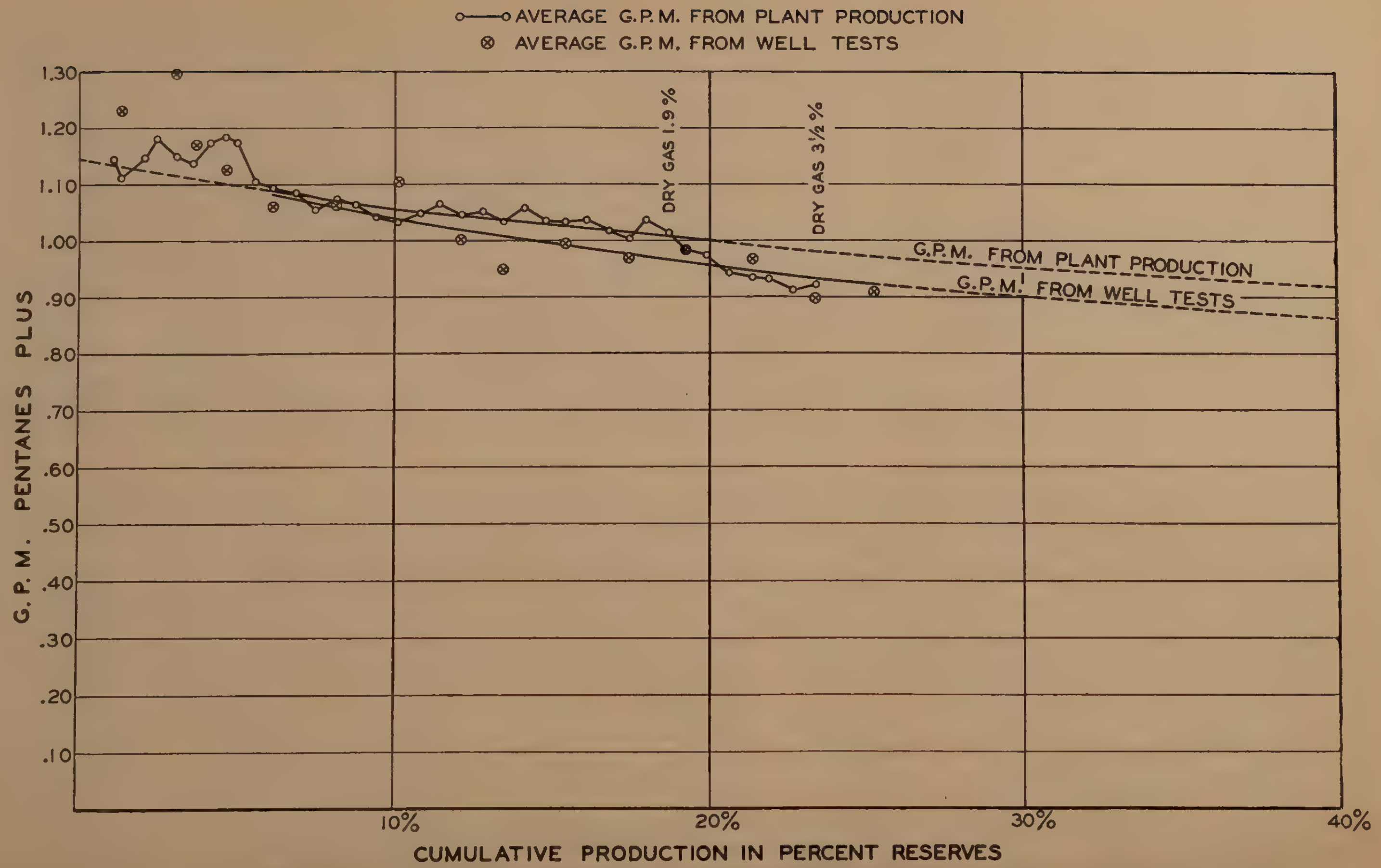


FIG. 14.—COMPARISON OF AVERAGE G.P.M. RECORDS FROM PLANT PRODUCTION AND WELL TESTS, LA GLORIA FIELD, TEXAS.

loss of 0.24 G.P.M. and the deeper wells 0.45 G.P.M., both on the cumulative basis and including solution gas.

The comparative behaviors of the three groups of wells are not what could be expected from the retrograde tests. The wells with the lean gases have shown approximately the same G.P.M. loss as the wells with richer gases although the pressure loss has been much less for the shallow wells. The wells not in cycled sands have had less G.P.M. loss than the wells in cycled sands although the initial G.P.M. was the same for each and although the wells in uncycled sands had suffered more pressure loss.

When the retrograde curves are computed to the rate basis and compared with the three curves in Fig. 15, the actual losses for the shallow wells are found to be so much greater than shown by the retrograde tests that they cannot be reconciled. The actual losses for the 26 deeper wells in cycled sands also are greater than shown by the retrograde tests and would be still greater if allowances were made for solution gas and for liquid flow of condensates into the wells, but it cannot be said positively but what more accurate data could not reconcile them. The rate of losses for the six deeper wells in uncycled sands are less than shown by the retrograde tests, but allowing for solution gas and inaccuracies they could reasonably be reconciled.

Too much significance should not be attached to the lower losses shown by the wells in uncycled sands because under depletion the bulk of the gas in the reservoirs will go through lower pressures and be subjected to much more severe retrograde conditions than in a cycled reservoir; hence their ultimate losses by condensation and retention can reasonably be expected to be greater than if cycled. However, the field data available to the writer give no basis for estimating how much more loss would be suffered.

Though these comparisons of laboratory with field data are unsatisfactory and incon-

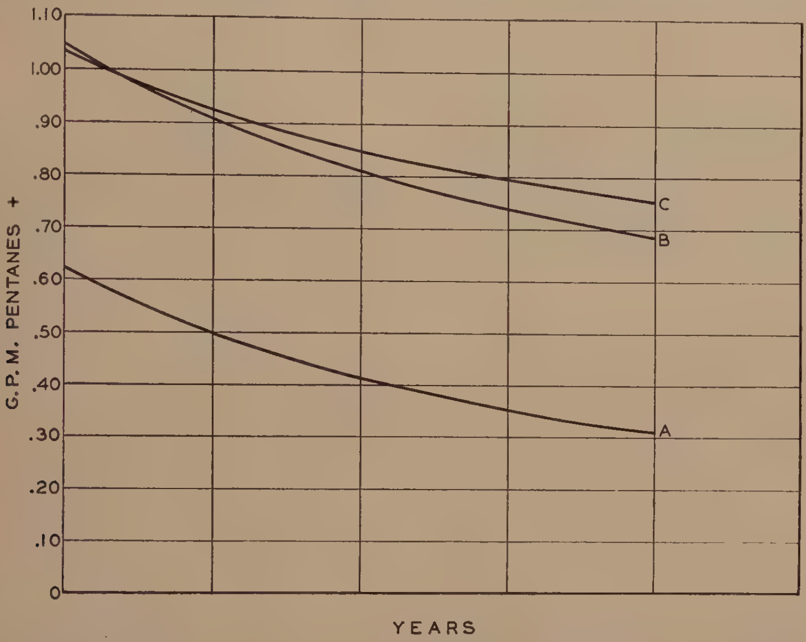


FIG. 15.—AVERAGE G.P.M. CURVES FOR THREE CONDITIONS IN STRATTON-AGUA DULCE FIELD, TEXAS.
A. Average of seven shallow wells in cycled reservoirs containing lean gases.
B. Average of twenty-six deeper wells in cycled reservoirs containing richer gases.
C. Average of six deeper wells in reservoirs not being cycled and containing richer gases.

clusive, there is enough evidence to throw some doubt upon the assumption that laboratory methods are fully analogous to reservoir conditions. On the whole, the evidence indicates that cycling is effective to a lesser degree in preventing retrograde losses than has been assumed. The writer suspects that the causes of dissimilarities between field and test data may be found in the pressure sinks formed around each flowing well. However, to reach valid conclusions with respect to the applicability of laboratory to actual conditions, it will be necessary to have more accurate data from more fields than were available to the writer, and the laboratory data will have to be presented in comparable terms.

ACKNOWLEDGMENTS

Besides the acknowledgments made in the references, the writer desires to thank Mr. Robert T. Wilson, President of La Gloria Corporation, and Mr. C. R. Williams, Vice-President of Chicago Corporation and Gulf Plains Corporation, for permission to use much of the material set forth in this paper; also, J. A. Putnam, G. G. Brown, H. T. Pruett, Kenneth Eilerts, R. C. Craze, A. S. Parks, W. Hurst, and W. C. Henderson, for material or discussions.

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A Study of Some Factors Affecting Gun Perforating

By S. C. Oliphant,* Junior Member AIME, and R. Floyd Farris*

(Galveston Meeting, October 1946)

Abstract

Presented in this paper is a summary of the results of experiments conducted in both the laboratory and the field during the past three years in connection with casing-perforation problems. Included are studies of gun features that influence bullet performance and penetration, and studies of the effect of perforator bullets on casing and the neat cement in the annulus. Discussion and data are also presented relative to the accuracy of depth measurements in deep wells.

Introduction

It is a common practice in the oil industry to effect the completion of oil wells by setting and cementing casing through the producing horizons and perforating the section of casing opposite the desired interval by means of a gun lowered into the well on a cable or on the tubing. This practice has been followed for some time, and this method of completion has been given considerable study by the companies that render perforating service as well as by the oil companies that utilize their services. Through continued research on this subject, it has been possible to develop guns, bullets, and powder that will permit controlled firing at great depths, and penetration of as many as two strings of casing.

It is the object of this paper to present the results of studies made of gun perforating in both the field and the laboratory. These studies were made to determine the factors that affect penetration of the bullet, burring of the casing, accuracy of depth measurements, and other items. It is hoped that by presenting the results of these investigations a better understanding may be obtained of certain of the factors involved in gun perforating and further investigation of the subject will be prompted.

Subsurface Tests

A well approximately 9000 ft deep, which was being prepared for abandonment, was selected for subsurface tests of gun-perforating experiments, In preparing the well for the experiment, 5½-in. casing in the hole was pulled and racked in the derrick. A test section of pipe, which consisted of 65 ft of 5-in. 18-lb J-55 casing centered inside 7-in. 28-lb N-80 casing, was placed in the derrick corner and the annulus between the two pipes was cemented from the bottom up with 16½ lb per gal neat cement, which was mixed and displaced with a cementing truck in the usual manner. After the cement had been allowed to harden for about a week, the test section was lowered into the hole on the 5½-in. casing to a depth of 6600 ft by casing measurements. The hole was filled with drilling fluid weighing 10 lb per gallon.

A perforating company was called to perforate the pipe, but was not advised that an experiment was being conducted. The company was asked to check the total depth (to cross pins in the bottom of the test section), then to raise the gun a given distance and fire a given number of shots with ½-in. bullets, pick up another distance and fire a given number of ⅜-in.

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bullets, and pick up another distance and fire a given number of ¼-in. bullets.

After this had been done and the company had left the well, another company was called and the same procedure was repeated. This was continued until each company servicing the area had perforated the test section.

The test section was pulled out of the well and inspected. Fig 1 illustrates the method followed in cutting the pipe to observe the results. Since it was found that very few bullets penetrated both strings of pipe, and since information was desired on the effect of perforator bullets on cement in the annulus at various stages of hardness (strengths), it was decided to repeat the first experiment, except that the test section would be run into the hole immediately after cement had been pumped into the annulus, and the perforating companies would then be advised of the nature of the test and specifically requested to perforate for maximum penetration.

A summary of the data relative to penetration of bullets as obtained from the first and second subsurface test is shown in Table 1. Table 2 shows the possibility of errors.

TABLE 1.—*Bottom-hole Perforating Experiment*

5-in. 18-lb. J-55 Inside 7-in. 28-lb. N-80

Bullets	Experiment No. 1, Standard Shots	Experiment No. 2, Best Shots
½-inch:		
Number of shots fired.....	31	21
Number went off..........	25	21
Number completely penetrating both strings.....	2	15
Number partly penetrating both strings........	23	6
⅜-inch:		
Number of shots fired.....	33	6
Number went off..........	27	6
Number completely penetrating both strings.....	5	6
Number partly penetrating both strings........	22	
¼-inch:		
Number shots fired.......	17	
Number went off..........	12	
Number completely penetrating both strings.....	2	
Number partly penetrating both strings........	10	

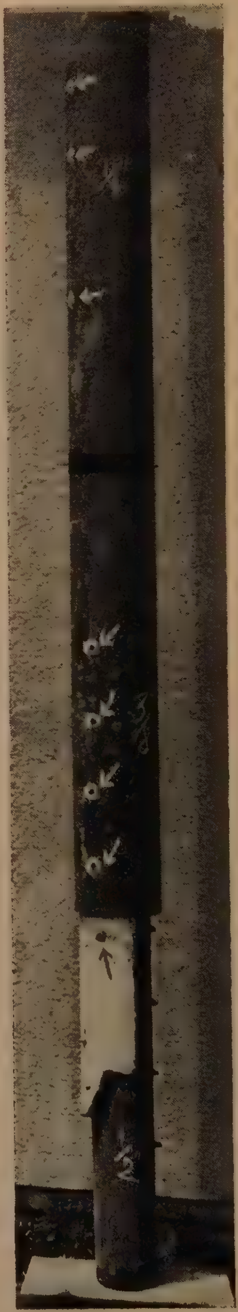

FIG. 1.—SECTION OF J-55 AND N-80 CASING WITH NEAT CEMENT IN ANNULUS.

TABLE 2.—*Possibility of Error*

Difference between Line Measurement and Casing Tally

METHOD OF MEASUREMENT	TOTAL DEPTH, FT
Stanolind casing tally	6,600
Perforating Concern A	6,594
Perforating Concern B	6,593.5
Perforating Concern C	6,597.5
Perforating Concern D	6,599

Errors Made in Placing Shots after Tagging Bottom and Picking up a Given Interval

Perforating Concern	Amount of Pickup, Ft	Error
A	13	1 ft high
B	25	2.5 ft high
C	37	0.5 ft high
D	50	2 ft high

These data show that considerable error is possible, even when the hole is perfectly clean and free of cuttings, and that when selecting an interval to be perforated allowances should be made for a possible error in measurement.

After the examination of both test sections of pipe removed from the hole had been completed, the blank sections in the pipe were cut out with a welding torch and each perforating concern was asked to perforate this section of pipe on the surface with the same powder charges, bullet sizes, etc., that were used in the subsurface tests. From these tests it was concluded that results from bottom-hole tests and surface tests are comparable insofar as bullet penetration and the effects of bullets on cracking and shattering of cement in an annulus are concerned. The subject of cracking of cement by perforator bullets will be discussed later in this report.

LABORATORY TESTS

After it had been concluded that gun-perforating tests conducted on the surface are representative of gun performance in deep wells, a series of tests was conducted at the laboratory to evaluate more fully some of the factors that influence the performances of perforating guns. The setup used in these tests is shown in Fig 2. It consisted of short sections of 5½-in. 17-lb J-55 casing cemented inside a thin sheet-metal form, which simulated the wall of the hole. This was placed in a 55-gal drum, which for some tests was filled with concrete, to simulate a hard formation, and for others was filled with unconsolidated sand, to simulate a very soft formation. Both the neat cement and the concrete were allowed to set until they approached maximum strength, except when a study was made of the optimum time (cement strength) required to perforate to avoid cracking the neat cement. In the latter case, the neat cement outside the 5½-in. casing was poured after the concrete approached its maximum strength and was perforated at various times after the neat cement attained its final set. Perforating was done with the barrel lying on the ground and the gun blocked up to center it inside the pipe. After four to six shots had been fired in the center third of the barrel, the metal barrel was cut with a torch and removed and the concrete was broken, to show the penetration and other behavior of the bullets. This is illustrated in Fig 3.

STUDY OF PENETRATION

The degree of penetration of the perforating bullet is dependent upon many factors. For example:

Powder Charge.—For any given gun design on the market, an increase in powder charge will produce increased penetration. However, quantity of powder is much more important to some gun designs than it is to others, and for that reason the performance of one type of gun should not be compared with that of another gun on the basis of powder charge alone.

Wet Powder.—If the powder in a gun becomes wet with well fluids, penetration of the bullet ahead of it is very apt to be seriously affected, regardless of the size of the powder charge. Wet powder usually is caused by faulty fluid seals.

Gun Size.—Gun size is important, for two reasons:

1. As a general rule, the larger guns have longer barrels or chambers than the smaller guns, and, all other factors remaining the same in a given type of gun, the longer the gun barrel the greater the penetration. For example, an increase in the barrel length of some guns of only ¼ in. will produce a greater increase in penetration than a large increase in powder charge. However, one should not compare gun-barrel length of one gun design with that of another gun design because there are other factors that must be considered.

2. Gun size is also important because both the subsurface and laboratory tests have shown that the closer the gun muzzle is to the casing the greater the bullet penetration. When relatively small guns are used inside 5½-in. or 7-in. casing the bullets fired from the side of the gun against the pipe may successfully penetrate the pipe and the surrounding cement sheath, but, according to laboratory tests, bullets fired from the opposite side of the gun may or may not effectively perforate the casing. Also, the penetration of bullets that strike the casing at an angle is invariably poor. These considerations indicate that best results will be obtained with the largest gun that can safely be run inside the pipe to be perforated.

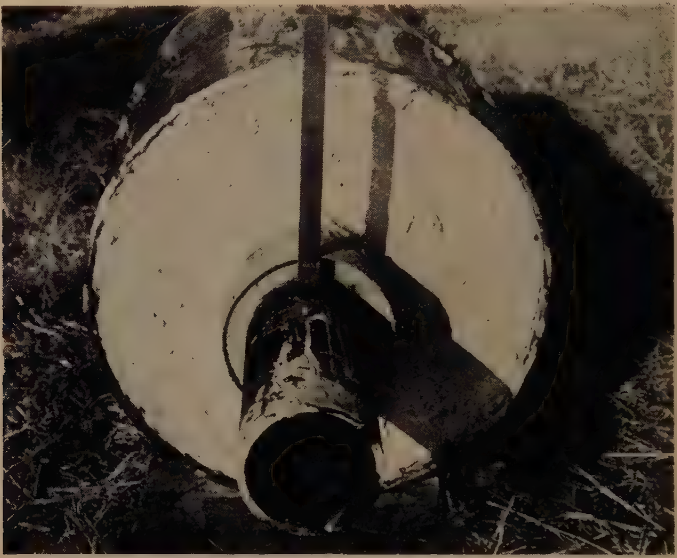

FIG. 2.—LABORATORY SETUP FOR SURFACE TESTS.

Shear Disks.—The shear disk in perforating equipment is a thin metal plate placed directly behind the bullet to create the effect of a closed combustion chamber. It allows a predetermined pressure to be developed before the disk ruptures and the bullet starts to move. A shear disk serves a purpose very similar to that of a tamp above dynamite in a shot hole. However, it should not be said that guns that utilize shear disks are more effective than those without a shear disk, because less powder is used in the former type than in the latter, to avoid exceeding the bursting pressure of the gun chambers. The shear disk probably is responsible for more difference in gun design than any other particular feature or factor.

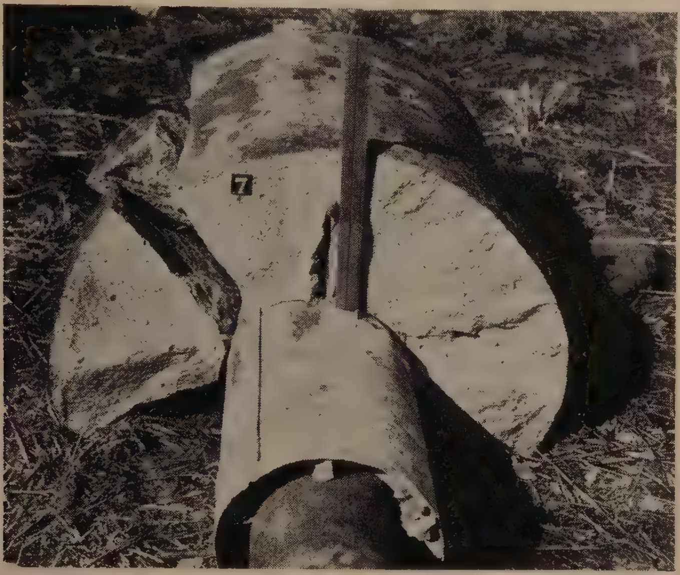

FIG. 3.—MEASUREMENT OF BULLET PENETRATION.

Bullet Shape.—The shape of the bullet nose has a great deal to do with penetration. Flat-nosed or perfect cylinder-shaped bullets produced very low penetration. Other odd-shaped bullets were fired during the laboratory tests, but none equaled the penetration of standard conical and ogival bullets. If there is a difference in penetration or performance between the two latter, it is believed to be of minor importance.

Bullet Size.—The size of perforator bullets for best penetration is not the same for all types of guns. Also, the test data contained a suggestion that the optimum size of the bullet determined by firing into very hard "formations" may not be the same size of bullet that will produce best penetration in soft, unconsolidated "formations." In general, however, it has been found that the optimum size of bullet usually falls within the range of 0.3 to 0.5 in. in diameter.

Sleeves or Bushings on Bullets.—Aluminum or plastic sleeves sometimes are slipped around ¼-in. and ⅜-in. bullets so that they may be fired through larger barrels. Tests show that cylindrical bushings used on bullets designed to be used with a shear disk greatly reduce bullet penetration. On the other hand, cup bushings—i.e., cylinders with only one open end, which slip over the back of bullets designed for use in guns that employ no shear disk —cause the smaller bullets to attain greater penetration than the larger bullets that require no bushing.

Worn Gun Barrels.—Gun barrels that had been discarded as junk were tested for comparison with new gun barrels. Gun barrels worn to a few thousandths of an inch oversize produced less penetration than new gun barrels. It was found in these tests with one type of gun that the penetration was reduced approximately 27 per cent with gun barrels that were worn on an average of 0.015 in. oversize. However, with guns of other designs this might not hold true, and other worn gun parts might have more effect on penetration than enlargement of the gun-barrel diameter.

Action of Bullets in Flight.—Observation of the position of bullets fired through casing, a sheath of cement, and into various "formations," together with an observation of the shape of the hole made by the bullet, afforded an opportunity to postulate the action of perforator bullets in flight. Bullets tend to follow a straight path with the point of the bullet forward while passing through the casing and neat cement, if the bullet path is normal to the pipe. The path of the bullet is normal to the pipe when it is perpendicular to a tangent to the pipe at the point where the bullet pierces the pipe. If the bullet path is not normal to the pipe, the bullet may start to turn while passing through the pipe and often will tumble or move sidewise during the remainder of its flight. Penetration in these cases invariably is poor. Bullets fired normal to the pipe wall continue to follow a fairly straight path out into the formation if the formation is hard. The bullets fired into homogeneous concrete "formations" were found usually with the point forward and resting at the greatest projection. Bullets fired normal to the pipe and into unconsolidated sand start to tumble after they clear the cement sheath. These bullets were found in every kind of position but generally with the back of the bullet forward. Also, these bullets would not always be found at the greatest projection. In a few instances bullets were found to have made as much as 2 or 3 in. penetration into the sand and then bounced back to the neat cement sheath.

Limits of Bullet Penetration.—Penetration of perforator bullets was measured as the distance from the back of the bullet (or point of the bullet in case the back of the bullet was found in the forward position) to the inside wall of the well bore. The length of the bullet was not considered in penetration measurements because the lengths of all perforator bullets are not the same, and because it is the amount of open hole behind the bullet that will determine whether or not the formation has
been effectively opened to the well bor
In this series of experiments, penetratio
were obtained ranging from approximate
2½ in. to no penetration at all. Thus, it
evident that not all of the bullets fired
presently offered perforating services w
effect complete penetration of even o
string of casing and the surrounding ceme
sheath.

Significance of Bullet Striations

Bullets often are found at the bottoms
wells inside the casing after perforatin
When a considerable number of bullets a
recovered the questions arise as to wheth
or not the objective formation has bee
exposed to the well bore, particularly if
production test has been unsatisfactor
Therefore, tests were conducted to d
termine whether bullets would be striat
in a characteristic manner, depending
the type of material they had penetrate
As demonstrated in Fig 4, this wo
showed that bullets fired through pipe a
caught in wood would not be great
marked. Only a slight smoothing down
the tool marks on the nose of the bullet w
observed. Bullets fired through casing, ne
cement, and into various formations show
deep striations on both the nose and t
base of the bullet. These bullets can be us
as a reference in making determinations
whether or not bullets that are bailed fro
wells are likely to have made contact wi
the formation.

Many of the bullets recovered from we
are broken in two or more pieces. Asi
from the fact that some bullet breakage
caused by improper hardening, many of t
bullets recovered from wells are believ
to be broken by the casing mill, which
run into the hole to knock out bullets th
are protruding inside the casing and
remove inside casing burrs. Bullet breaka
is also believed to be caused by the fa
that all bullets do not strike the pi
straight when the gun is off center in t
hole. During laboratory tests where the g

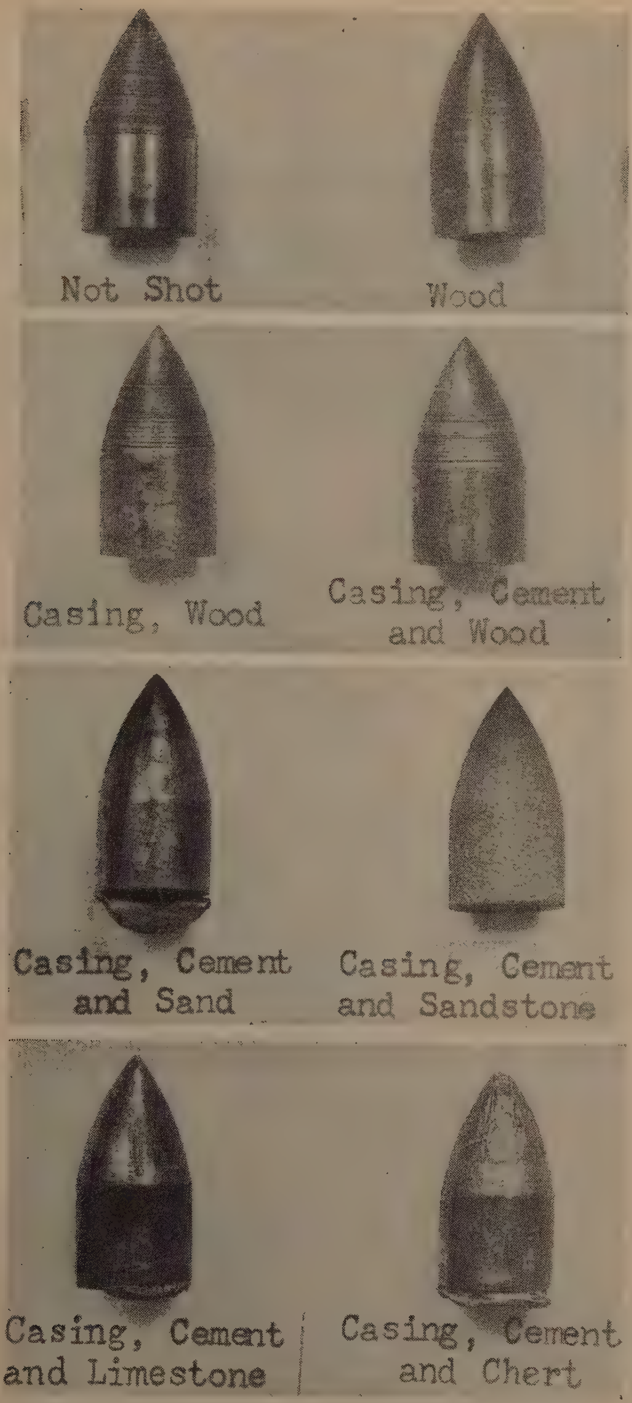

FIG. 4.—APPEARANCE OF BULLET AFTER PENETRATION.

was always centered very few bullets were found to be broken, perhaps no more than one in one hundred. Breakage of bullets during the subsurface test where the gun was probably resting against the pipe, however, was much more extensive.

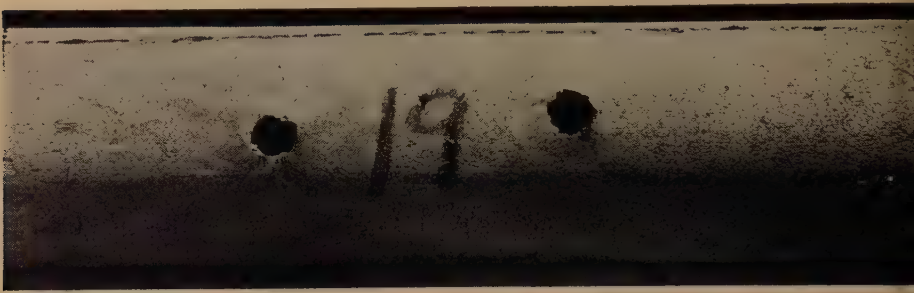

Fig. 5.—Appearance of cement in annulus when perforated after a WOC period of 1
hours (145 psi tensile strength).

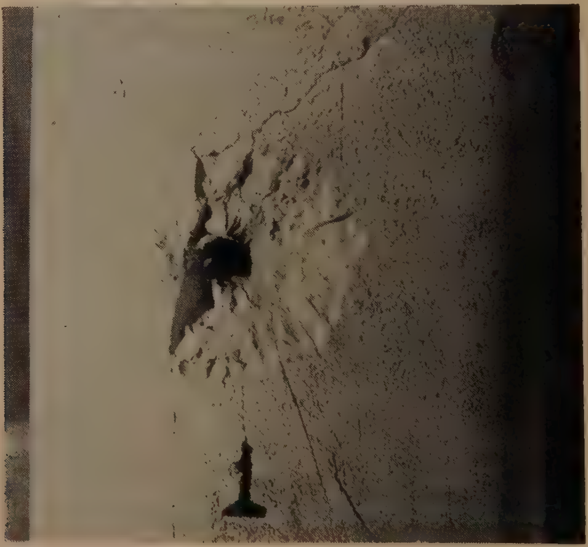

Fig. 6.—Cement-perforated after WOC period of 50 hours (307 psi tensile strength

Effect of Perforating on Casing

As the perforating bullet penetrates the casing while traveling at a high velocity, there is a flow of metal first to the inside of the casing and then to the outside. The flow of metal to the inside of the casing produces a sharp, ragged burr, which makes it hazardous, if not impossible, to run tool especially packers, through the perforate interval. For this reason a casing mi usually is run into the hole to knock o the sharp metal burrs before any attem is made to run a packer past the perforate interval. Milling out burrs is expensive an often hazardous, as the casing sometimes split or "egg-shaped" by the perforatin gun, causing the mill to stick or hang up.

Several of the perforating services r cently have placed on the market bulle that are said to leave no burr on the insi of casing. Laboratory tests show that whi certain special bullet designs will eliminate or reduce inside burring of casing, as a general rule penetration is sacrificed. Service companies should be encouraged to improve upon this development, at least to the point where casing burrs can be eliminated without sacrificing penetration under that presently produced with standard bullets at the maximum powder charge.

Perforator bullets can and do sometimes split casing. Although all of the factors that contribute to splitting of casing have not been studied by the writers, it is believed that the strength or rigidity of the material that surrounds casing when it is perforated has more to do with splitting of casing than any other single factor. H-40 pipe perforated on the surface, with no fluid inside the pipe and with no reinforcement outside the pipe, will usually split. The same test conducted on J-55 or N-80 pipe, as a general rule, will not split. However, J-55 pipe perforated with fluid inside the pipe and with no back-up outside the pipe will usually split. In no case during the course of the experimental work on gun perforating has J-55 casing been split by perforating when the casing was firmly backed up by strong cement or concrete. Thus, it appears that most casing splitting during perforating jobs may be attributed to the combined effects of poor cement jobs and perforating casing under fluid. It is possible that the effect of perforating casing under fluid is to concentrate the force of the powder blast to a smaller area on the wall of the casing.

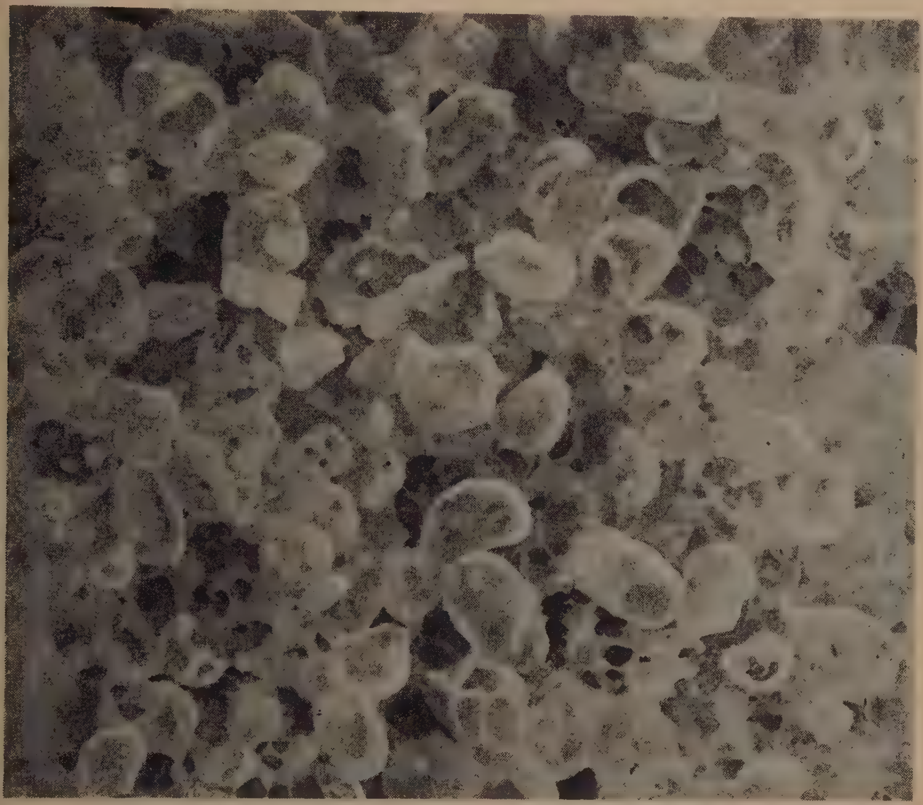

FIG. 7.—FRESHLY BROKEN SURFACE OF OKLAHOMA WILCOX SAND.

Another factor having to do with splitting of casing is the size of the bullet used. Large bullets must displace more metal than smaller bullets, hence the tendency to split casing is magnified.

Fig. 8.—View of bullet buried in Wilcox sand.

Tension in pipe in a well has been suggested as a possible cause of splitting of pipe by perforator bullets. A section of unsupported J-55 17-lb casing perforated in air under a tension of 40,000 lb did not split. It was perforated once in the collar and once below the collar.

Both the surface and the subsurface tests indicate that casing splitting by perforator bullets may be reduced or minimized by: (1) good cement jobs behind the pipe, (2) not perforating the pipe while the cement is too "green," (3) use of J-55 or N-80 grades of casing, and (4) use of the smallest practicable bullet.

Effect on Cement in the Annulus

In order to study the effect of perforating on the cement sheath in the annulus, subsurface tests were made in the 6600-ft wel with cement that had been allowed to se different periods of time. After the tes section had been pulled from the hole an the outside casing removed, to expose th cement in the annulus between the 5-in and 7-in. casing, it was found that cemen perforated too soon resulted in an enlarge hole and that cement perforated after pro longed aging resulted in considerab shattering and cracking. Fig 5 shows th appearance of the cement when perforate after 19 hr. or at an estimated tensi strength of 145 psi. Neat round holes wit no cracking or shattering of cement we obtained at this time. Fig 6 shows the r sults of perforating cement at 50 hr whic had developed a tensile strength of approx mately 307 psi. In this case considerabl cracking and shattering of the cement w noted. From these data it is evident th cement may be perforated satisfactori when it has reached a tensile strength approximately 150 psi, whereas a tens strength of about 300 psi results in cracking and shattering. The WOC time to a cement tensile strength of 150 psi will vary with depth, but in the subject 6000-ft test well the time was approximately 20 hr. It was also proved by laboratory tests that cement backed up by soft formations shattered more in perforating than did cement backed up by hard formations. These data indicate the necessity for perforating cement at the proper ages or strength, in order to eliminate cracking that might allow entrance of water or gas from below or above the perforated interval.

EFFECT OF PERFORATING ON PRODUCING FORMATIONS

As stated before, it was observed while making the study of the effect perforator bullets on cement in the annulus that when cement is perforated while it is relatively "green,"—say, at a tensile strength of less than 100 psi—relatively larger holes are blown in the cement by the blast of the powder. These holes often are as large as 2 to 3 in. in diameter. This observation raised the question of what happens to the cement that is displaced by the blast of the powder. Where does it go? Visual examina-

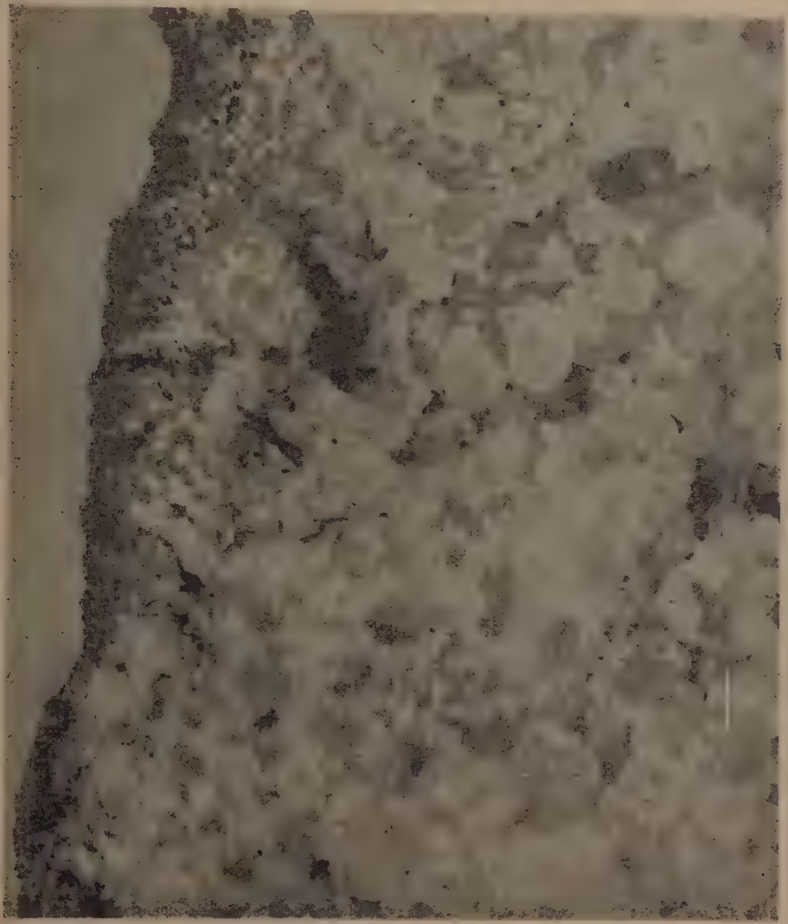

FIG. 9.—SECTIONAL VIEW ILLUSTRATING SAND COMPACTION ADJACENT TO PATH OF BULLET.

FIG. 10.—VIEW OF SAND FACE IN THE HOLE MADE BY THE BULLET.

tion of the relatively large holes made in "green" cement showed very clearly that most of the cement displaced from the hole is forced back into the pore space of the surrounding cement by compaction. The zone of compaction in many cases was clearly defined. This, in turn, raised the question of what happens to formation materials displaced by perforator bullets. Does it force the displaced material back into the pore space of the pay zone and reduce its permeability?

This point was investigated by perforating a large Oklahoma Wilcox-sand core mounted in a cement block, for good backing. Micrographs were taken of the sand before and after perforating. Fig 7 illustrates the appearance of a freshly broken surface of the sand before it was perforated. Fig 8 shows a section of the ¼-in. perforator bullet buried in the sand as exposed by cutting the core in half in th direction of the path of the bullet. Fig is another sectional view illustrating san compaction. The ledge to the left is a par of the hole made by the bullet. Sand grain adjacent to the bullet path are crushed an compacted as compared to the sand grain some distance back from the bullet path Fig 10 is a view of the sand face in the ho made by the bullet.

Other tests were made where the relativ reduction in permeability due to perforato bullets was measured. Included in thes tests were limestones and dolomites as well as sandstones. These tests confirmed the suggestions indicated in the micrographs. They indicated also that the lower the permeability the greater the proportion of reduction in permeability. The reduction in permeability found during these tests varied from 40 to 80 per cent, depending upon the original permeability of the formation.

This factor may serve to explain at least partly, why it is often quite difficult to bring a well in or to get a satisfactory well test through perforations in some tight formations. It may also shed an interesting light on the question of why it is often necessary to acidize perforated completions to obtain a satisfactory well test.

ACKNOWLEDGMENT

The writers wish to express their appreciation to the management of the Stanolind Oil and Gas Co. for permission to prepare and publish the results of these experiments and to the pertorating concerns for their excellent assistance and cooperation in the execution of many of these tests.

DISCUSSION

E. B. MILLER*—The paper presented by Mr. Farris has been most enlightening and the authors and Stanolind Oil and Gas Co. are to be commended for making the results of their experiments available to the industry. With the findings of these experiments I am sure that operators can more intelligently explain some of the troubles they have encountered and can also use, to real advantage, the facts that have so clearly been illustrated.

I am not in a position to take issue or confirm the data presented; the results of the experiments have been very clearly and accurately reported. There are, however, some points that should be emphasized in applying these findings to actual field problems. The findings indicate that it is not as simple a matter to perforate two strings of casing as many of us have been led to believe, but there are so many successful jobs that we know it can be done. The most important point in ensuring a successful job is to fully acquaint the perforating company with the facts prior to the time they are ordered out and not after they have arrived on location. To plan a successful job and select the proper equipment consideration should be given to the relative sizes of the casing strings to be perforated, the grade casing, the size hole drilled, temperature and depth, as all of these factors have a direct bearing on the job. It must be kept in mind that the perforating companies have a varied assortment of tools and each is designed to do a better job under certain conditions. I feel sure that a real saving can be made to the operator in avoiding unnecessary delay, misunderstandings, and in some cases job failures if he will be as diligent in acquainting the service companies with all the facts as he expects them to be in the performance of their job.

Every branch of the industry is anticipating the requirements and problems that will be encountered as we drill deeper and deeper in the search for oil. As wells are drilled deeper, higher temperatures will be encountered, and high temperatures present a real problem and one of the most important factors affecting gun perforating. Upon inquiry, I found that the perforating service companies have tackled this problem in a realistic manner and a great deal of research is now in progress to solve this problem. The experiments reported in the paper just given did not cover the effects of temperature on gun perforating, and I believe it will be of interest to many of you to pass on to you some of the information I obtained while making inquiries as to what is being done about perforating "hot wells."

One of the first things that was called to my attention was that the combined powder used by all perforating companies is such a small quantity when compared with other uses powder is put to that the major manufacturers of powder have no great incentive to apply their research facilities to the problem. It is a problem that apparently must be solved in the laboratories of the service companies. I use the phrase "must be solved" purposely because the oil industry and its allied services has a reputation for solving difficult problems, and this will not be an exception. When we consider that all powder made today is specifically designed for some other use than gun perforating, it becomes apparent that research and development is going to have to start away back in the chemistry of explosives.

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* Tide Water Associated Oil Co., Houston, Texas.

The explosion of powder is a chemical reaction and two of the controlling factors are time and temperature. In deep hot wells, both of these factors are encountered. Quoting from a recent publication on explosives, "Chemical reaction and rate of chemical reaction increases with rising temperature, doubling in many cases for each rise of 10°C in temperature"—this relationship between temperature and time explains the fundamental problem to be overcome in developing an explosive for deep hot wells. The melting point of most cellulose products is in the range of 320° to 340°F, and since nearly all powder is nitrocellulose, its critical temperature is in that range.

In shooting hot wells at the present time every precaution should be taken and consideration given to the time as well as the temperature factor. If the proper time and temperature relationship is reached for the chemical reaction to take place rapidly, the powder is going to explode regardless of any detonating devices, physical characteristics of the gun or safety devices. This explains why some guns have gone off on the way out of the hole after they were supposedly fired on bottom. Some of the precautions that can be taken are to make a trial run with a dummy gun to test the mechanical condition of the hole and the time required to reach the desired depth. Accurate temperature readings at the perforating depth should be obtained on all wildcat or deep wells. It is good practice to leave the gun in the perforated zone for a period of time to ensure the explosion of any duds that may be in the gun; this may save perforating the pipe on the way out of the hole.

In closing, I would like to emphasize the importance of good planning in any perforating job and am sure that the results of the experiments conducted by the authors will be of real benefit in making such plans.

W. M. PICKLES*—Mr. Oliphant and Mr. Farris are to be congratulated upon the thoroughness with which they have conducted the gun-perforating experiments. In general, the conclusions they have reached coincide with those obtained by others in the industry especially the gun-perforating service companies.

There are a few points raised in the paper on which a few comments seem appropriate. The statement was made that experience indicates that surface tests will be indicative of the performance of the gun in wells. This statement might be correct as a general rule, at least in a qualitative manner, but other experiments have indicated that in some cases surface tests may not be taken as conclusive as to the performances in deep holes. Penetration is one of the factors that do not always seem to be the same in the two cases. Hundreds of tests have been made in a test well that simulates deep-hole conditions both as to temperature and pressure, and in general it has been found that the penetration is slightly better in the deep-hole tests than with tests made at surface temperatures and pressure. This may vary with the types of gun used.

The statement regarding wet powder should be emphasized. The power developed by almost all propellant powders used in gun perforation is greatly decreased by the presence of moisture in the powder. I should also like to confirm the point that the performance of large-diameter guns is superior to that of the small-diameter guns.

The discussion of the use of no-burr bullets might be elaborated on. The statement was made that penetration is "sacrificed" when a no-burr type of bullet is used. The penetration is less when the no-burr bullet is used, but it seems improper to refer to the penetration as "sacrificed." Hundreds of laboratory tests confirmed by field reports have been made on different types of devices for providing burr-free holes, and it is admitted that the design is quite critical. The shape, material, and the weight of the no-burr device are all quite important. Burr-free perforations can be made with a loss of only ⅛ in. of penetration in steel: that is to say, if enough casings are provided about the gun so that the projectile does not traverse all of them, the projectile usually penetrates only about ⅛ in. further if the no-burr ring is omitted, other conditions being identical. It is true, however, that the penetration might be reduced as much as 25 pct if the no-burr ring is not properly designed. The design is different for different types of guns and different sizes of bullets.

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* Schlumberger Well Surveying Corporation, Houston, Texas.

In discussing the action of the bullet in cement, the statement was made that most of the displaced cement is forced back into the pore space of the surrounding cement. The proof is so conclusive that no exception could be taken to it; however, it is well known that some of the material finds it way back into the well. Samples frequently are recovered by the gun perforator. If the perforating gun is stationary when the bullet is fired, so that the gun remains approximately at the depth of the perforation, samples of the formation into which the bullet has been fired are often found in the powder chamber of the perforator. When the perforator fires, the gas leaves the powder chamber after the projectile and the borehole fluid rushes into the powder chamber, and formation samples are very often present in this mud that enters the chamber. This also is a rather convenient and well recognized way of checking that the bullet penetrated the casing and went into the formation.

It was stated that the perforating operation should be made at the optimum time following the cement job, as thoroughly cured cement is fractured by the perforating operation. This is a point to consider when perforating a rather thin zone, but when a large interval is to be perforated it seems that breaking up the cement in the interval would actually be an asset to the production rate rather than a hindrance. Of course, in this case it would probably be well not to place any shots in the top and bottom one or two feet of the zone.

One point that has not been touched upon in this paper is the unintentional ignition of perforating guns in hot wells. The phenomenon of igniting propellant or slow-burning powders as used in gun perforations is not very thoroughly understood by most operators. Propellant powders are all unstable nitrogen compounds and the ignition and explosion of powders is purely a chemical reaction. As they are unstable compounds, the atoms are always trying to rearrange themselves to some different types of molecules. As is true with most chemical reactions, the rate of the reaction is increased with increases in temperature. The process of igniting the powders is simply and purely one of time and temperature; both factors are essential. For example, the statement will be found in the literature that the decomposition rate of powder doubles in many cases for each rise of 10°C. A pure gun cotton without stabilizers may be expected to have a stability life of 10 years at 0°C, and its decomposition rate doubles for each 7°C rise in temperature. If stored in a magazine near a steam radiator that is 100°C, the gun cotton would be expected to explode in about six hours. This temperature effect is common to all explosives. Certain forms of nitrocellulose, a principal constituent of smokeless powder, will explode within 5 sec at a temperature of 365°F. The power of a powder is almost proportional to its nitrogen content, but the burning rate, that is the time at which the maximum pressure is produced, and the duration of the high pressure varies greatly with different powders. The science of manufacturing gun powders is very old, and a huge number of powders are available, but unfortunately none of the regular powders are designed for gun-perforating work. These powders were designed to be used in pistols, guns, rifles and artillery pieces all of which have a barrel much longer than can be provided in a gun perforator. Powder for a gun perforator is therefore a special problem. It is hoped that in cooperation with the powder companies some more suitable powders may be developed. The problem is not a simple one, and even if a powder is developed for one gun it may not be entirely suitable for another type of perforator. The development of special powder that will withstand high temperatures for a reasonable time has been very slow, but there are now a few experimental powders available which it is believed will be better suited for perforating deep hot wells. The progress in this regard is very encouraging, and it is hoped that in a short time the problem of ignition by high temperatures will be a thing of the past.

N. L. Dorn* and V. L. Forsyth*—The Stanolind Oil and Gas Co., Mr. Oliphant, Mr. Farris, and other engineers and field men are to be highly complimented for this excellent investigation of gun-perforator performance. Service companies are limited through lack of knowledge of many details such as cement behavior, formation variables, and the like in conducting similar studies. It is only through cooperative ventures of this nature that such extremely important problems can be satisfactorily solved. We have enjoyed working with the Stanolind group and hope to continue further studies as the need becomes known.

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* Lane-Wells Co., Los Angeles, California.

Mr. Oliphant and Mr. Farris have presented their findings as they might be interpreted by oil company personnel. This same information interpreted from the service company standpoint may present thoughts of interest to oil operators and may assist in putting to work some of the knowledge imparted in the paper. It is with this sincere desire in mind that we present comment as follows:

Well-depth Measurements

The service company problem is to lower a cable, which for practical purposes may be considered a coil spring, as deep as 3 miles into the earth; through a corkscrewed hole; with varying weights and volumes of instruments; through fluid of varying density; at speeds up to 1000 fpm, and still measure at all depths with unquestionable accuracy.

This problem has been paramount in our research activity. Great progress has been made in cable structure. Formulas suited to determining the stretch characteristics of individual cables and individual sections of cable have been developed. Field installation and calibration procedures incorporating corrections for fluid density and instrument weight have been set up under the direction of field engineers. Yet in our estimation, where completions require accuracy approaching inches instead of feet, it is necessary to utilize available methods that establish exact relationships between formations and casing collars.

Accuracy in Picking Up from Bottom

In analyzing the table showing errors in pickup from bottom experienced by the four service companies, it should be realized that these errors are not accumulative and are, in fact, quite different from errors in depth measurement. They represent varying amounts of slack in weight indicators and are approximately the same regardless of the distance picked up from bottom.

The results of the tests covered by this paper show that complete penetration was not accomplished through the two cemented strings. Although we cannot refute the results of the penetration tests, we must recall that the conditions of the test were abnormally severe and should not be considered as a measure of efficiency of all two-string perforating jobs.

Knowledge of Well Conditions

A thorough knowledge of conditions present in a well is essential to best treatment of that well by the service company. Information concerning the number of strings of casing present, casing weights and grade, casing size, size of drilled hole, and subsurface temperature, is necessary to properly gun-perforate the well. Advance notice is a "must," particularly if abnormal well conditions, casing sizes, etc., exist or if an unusual size or piece of perforator equipment is desired (bullets, for instance).

Best handling can be assured by making certain that responsible service companies are contacted.

Penetration

The paper has pointed out the effect of barrel wear and leakage of well fluid into the gun upon penetration. A new gun fired at the surface will easily bury a bullet in a solid steel bar. As barrel wear occurs, penetration is reduced. Fluid leakage may allow moisture to accumulate in the powder recess, where under subsurface conditions it vaporizes with resultant slowing of the burning rate of powder. In addition to these two possible difficulties, there exist other problems peculiar to individual gun types.

It is the service company's obligation to recognize these potential trouble spots and to take preventive action to assure that adequate tools and instructions are provided for a well organized, systematic inspection system in the field.

The oil operator should realize that in gun design, as in most things, the tool that is used is a compromise. Bullets sometimes return into the well bore after penetrating casing and formations, therefore sufficient clearance must be provided to assure that such "bounce backs" will not interfere with gun movement. The steel used is capable of standing certain maximum combustion pressures, and this limits powder charge and thickness of shear disk.

Casing size definitely controls gun diameter and indirectly reduces barrel length, bullet weight, powder charge, and similar variables. With increasing frequency, we are called upon for emergency treatment of wells upon which there have been drilling or completion troubles. These usually result in two-string penetration requirements with the inner string a very small diameter casing, for instance, 4¾ in., or tubing, or sometimes 3½-in. or 4-in. drill pipe. For these jobs, we must substitute modified equipment, which may present certain operational hazards not found in standard equipment. In planning a completion program, especially where there is possibility of deepening for future liner recompletion, thought should be given to the gun-perforating problems involved, and the use of any unusual casing sizes should be discussed with service company engineers during the planning period.

Burr-free Bullets

Our first development work in attempting to gun-perforate without leaving a burr took place prior to 1940, the first patents being issued in 1940. In all the work conducted to date, satisfactory removal of burrs has been accomplished only at a loss in effective penetration. Since strenuous efforts have been directed toward increasing penetration to meet increasing field requirements, we have been reluctant to advocate the use of "burr-free" bullets.

As an outgrowth of this study, the ogival-nose bullet was developed. Its primary advantages lie in the fact that the center of gravity is further forward than in any other design, with lesser resultant tumbling tendencies; and in the fact that the strong point structure reduces point breakage with resultant less tumbling. The over-all result is greater average penetration and slightly improved burr characteristics.

Bullet Striations

The information shown in Fig 4 should be retained by everyone using the gun-perforator service. It can serve as a guide for analyzing troubles that occur in well completion. If a well, supposedly a producer, gives up no fluid after gun perforating, there may be lack of penetration. If bullets are bailed from the well, they can be studied to determine the trouble. Perhaps they will indicate casing penetration but no formation penetration; the obvious solution is increased shot density in the critical area. In some instances, recovered bullets may show formation markings, which indicate that well-depth measurements may be the source of trouble. Many similar studies are possible.

The exact reason for bullet return to the well bore has never been fully explained, although several theories have been presented. In some cases, bullets have returned to the gun-barrel bore with the point reversed, where conditions were such that the bullets could not have been loaded upside down by reason of a shear disk attached to their base, and where clearance between gun and casing was inadequate to permit the bullet being turned around within the casing.

Reduction of Formation Permeability

The combustive pressures within a gun sometimes approach 200,000 psi. It is quite logical that there might be some compaction of the formation within the immediate vicinity of the perforated hole as a result of expanding gas. Although we have not investigated this matter of permeability reduction fully, it is believed that increased shot density, fired in such a way that each following shot will receive the cracking benefits of preceding shots, will cause radiating cracks that will result in satisfactory effective permeability.

Casing Bulging or Egg Shaping

The writers have indicated the possibility of egg shaping of casing. This might be attributed to: (1) egg shaping created by the gun; (2) egg shaping caused by the mill in removing burrs caused by the gun.

We have often considered the problem of pipe deformation as a result of gas action from the gun. In this interest, it is highly desirable to use a design that utilizes a minimum amount of powder without sacrificing penetration. These characteristics are built in to the gun design and are the results of much development. Another factor, of course, is the matter of firing shots one at a time or all at once, with arguments in favor of each method.

It has been a pleasure to present this discussion of Mr. Oliphant's and Mr. Farris' paper. The overall good that has resulted and will result from this extensive study should contribute to a better understanding of the problems involved.

T. S. West*—For the case of gun perforations through cement that has been aged, what is the maximum and average distances to which resulting fractures extend from the point of perforation?

Was any difference noted in the extent of fracturing of cement between guns that fire several bullets simultaneously and those that fire one bullet at a time?

S. C. Oliphant (author's reply)—No crack more than 2 ft long was noticed; the majority were of 1 ft and less in length.

We have very few data on the subject of Mr. West's second question, and do not believe a conclusive statement could be made, although I do not recall any marked difference in fracturing when perforating all shots simultaneously or one at a time.

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Use of Plastics in Consolidating Loose Sands in Wells

By R. H. Smith* and A. C. Polk, Jr.,* Member AIME

(Galveston Meeting, October 1946)

Abstract

The physical properties of the materials are listed, together with a short explanation of how this material binds the sand grains together without materially reducing the effective permeability of the sand. The chemical can be used in wells with bottom-hole temperatures ranging from 105°F to more than 350°F. A description of the equipment required and the techniques used for applying these plastics to the wells is included.

Introduction

Recovering oil and gas from unconsolidated sand formations offers one of the most troublesome of all production problems. These sands generally present no particular trouble while drilling is in progress, but after the well has been completed and a pressure differential has been established across the face of the producing zone, the formation begins to "slough," resulting in "sanding up" of the well. The term "sanding up" means that sufficient volumes of sand have moved into the well bore or casing to cause a serious reduction or complete halt of all flow of oil, water or gas. In rare cases a well may produce only a small amount of sand and still continue to flow or pump, the sand being carried to the surface in the fluid stream. However, in such instances, the result may be a costly repair bill due to the effect of the sand on surface and pumping equipment.

The difficulty of producing petroleum from sands that are loosely cemented has long been recognized by petroleum engineers but only within the last few years has any new approach to the problem been undertaken. This involves the use of plastics that are capable of bonding the individual sand grains in place without materially reducing the effective permeability of a formation. The successful application of plastics for the consolidation of poorly cemented sands is relatively recent but now it is widely used in many of the more difficult areas on the Gulf Coast of Texas and Louisiana.

This relatively new use of plastics[1] in the oil fields has been preceded by much laboratory and field research on the use of various chemicals[2,3] for solving numerous well-completion and work-over problems. Plastics now are being used successfully to control gas-oil and water-oil ratios,[4,5] in zone isolation, the repair of casing leaks, the elimination of caving in cable-tool drilling wells[6,7] and in the setting of liners[8] and casing.[9] Sand-consolidating plastics, however, are basically different from all others in that they must not form an impervious seal.

Field Practices

The approach to the sanding-up problem usually has been the mechanical obstruction of the movement of the sand grains.

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* Dowell Incorporated, Houston, Texas.

[1] References are at the end of the paper.

However, all such methods are limited in that the sand movement is stopped not at its source but at the bore of the well, and such methods must rely on the use of various types of screens and gravel packing.

Wells that are completed in the more consolidated sands seldom offer any particular difficulties due to sanding up until they begin to produce water. The movement of the water through these sands dissolves the cementing materials that originally were in place, thereby allowing the movement of the sand grains proper, which finally causes the well to "sand up." When water makes its appearance in a well, more fluids must be produced in order to obtain the daily allowable. This increased production creates higher fluid velocities through the sand, increased erosion of the cementing materials, faster movement of the sand grains and rapid destruction of the screens. Once such a condition exists, an operator may find it uneconomical to continue setting screens and cleaning out, and the result may be the early abandonment of the well.

Effect of Permeability

The basic prerequisites for plastics to be used in wells for the consolidation of loose sands are that they must penetrate the sand at low pressure, possess adequate compressive and tensile strength in a solid state, and, when solidified, exhibit inherent permeability.

Numerous studies made in the laboratory, in an effort to plug a consolidated sand core with these plastic materials, resulted in a permeability reduction in the order of only 50 to 70 pct. However, most of the producing sands to which these plastics have been applied often exhibit permeabilities as high as 2 darcys, in which a reduction in permeability of as much as 70 pct would be of no particular consequence. Actual field-production data obtained from wells where friable producing formations have been consolidated with plastic show that the effective permeability usually is reduced by no more than 10 to 15 pct.

As the mechanism of sand consolidation through the use of plastics relies upon a bonding of the individual sand grains in the formation, with a related loss in permeability, the type of well to which this service is applicable is indicated clearly. Usually it may be assumed that any formation that has a combination of an effective reservoir drive plus a high permeability may be successfully consolidated, but when the reservoir drive is not effective, or when the permeability of the sand is low, the chances of securing effective sand consolidation are reduced.

Basic Prerequisites

While the foregoing considerations are of primary importance, various other factors play an important part in the successful application of sand-consolidating plastics. Among these are bottom-hole pressure and temperature, water-oil and gas-oil ratios, gravity of the oil, type of reservoir control, producing status, size of hole, production history and type of completion. An analysis of these items will determine the technique of application, the volume of material required and, to some degree, predict the ultimate result. Because of the inherent chemical properties of the plastics, suitable catalysts are required to control their setting time, the selection and amount of which is determined by the bottom-hole temperature of the well. It follows, therefore, that fairly accurate bottom-hole temperature determinations must be made.

When wells that have produced large quantities of sand are considered for treatment, it is highly important that the producing interval be squeezed with a material that will lend competence to the formation immediately adjacent to the well bore or casing. Such operation is required because it is believed that, in wells of this type, the formation in the critical area is in a semifluid state, and before sand-consolidation plastic can be applied successfully the formation in the area near the well bore must be treated with a material that will give it the required rigidity. Following this step, the reinforced sand may be gun-perforated over the desired interval and the sand-consolidating plastic applied to the formation through the gun perforations. Another fundamental requisite for the success of any sand-consolidating application is the absolute isolation of the affected zone. The lack of a proper bond between the casing and the formation will permit the fluid plastic to travel along the side of the pipe rather than to flow laterally into the desired producing formation. In order to emphasize these two basic requisites, each of which is dependent upon well conditions, it should be noted that wherever this procedure has been followed the sand consolidation with plastic has been successful except where a bottom-hole temperature of less than 125°F has been encountered.

TABLE 1—*Pertinent Data*

State	Pool	Producing Horizon	Bottom-hole Temperature, Deg F	Producing Interval, Ft	Plastic Used, Gal	Maximum Injection Pressure, Psi	Remarks
Texas.....	Withers	Erie	150	5,522–5,524	105	600	New zone completion. No sand movement following plastic
Texas.....	Picket Ridge	Marginulina	132	4,690–4,692	75	2,200	Completed with screen pumping. Following plastic, natural flow
Louisiana..	Erath	Miocene	165	7,731–7,744	250	2,000	Producing 4 pct sand prior to treatment. No sand following treatment
Texas.....	S. Cotton Lake	Frio	156	6,480–6,483	150	1,400	Well sanded up and abandoned. Following plastic, produced on natural flow
Texas.....	Cedar Pt.	Miocene	135	4,250–4,254	150	2,500	New zone completion. No sand trouble following plastic
Louisiana..	N. Crowley	Miocene	150	4,822–4,836	250	1,000	Producing sand prior to treatment. Pipe-line oil following plastic
Louisiana..	Leeville	Miocene	180	7,770–7,805	330	2,400	Screen sanded up; now flowing through casing perforations
Texas.....	Thompsons	Frio	140	5,385–5,391	150	1,075	Originally completed with screen. Following treatment, producing through casing perforations, no sand
Texas.....	Lefever	Cole	110	1,759–1,763	150	200	Sanded up. After treatment, pumping 40 bbl per day
Louisiana..	Delta Farms	Frio	160	6,929–6,932	110	1,500	No sand troubles following plastic application
Texas.....	Wade City	McNeil	160	4,890–4,906	100	1,000	Producing sand before treatment; pipe-line oil after
Texas.....	Barbers Hill	Oligocene	145	4,055–4,085	225	1,250	Producing pipe-line oil, natural flow, following treatment
Texas.....	Pierce Jct.	Frio	145	4,708–4,730	100	1,000	Following treatment, producing 91 bbl daily, no sand
Texas.....	Barbers Hill	Oligocene	135	4,055–4,085	222	1,200	144 bbl daily production with no sand difficulties following plastic
Texas.....	Barbers Hill	Oligocene	112	4,260–4,290	200	1,250	Producing 155 bbl daily following treatment; no sand
Texas.....	Freer	Cole	107	1,722–1,725	100	200	60 bbl per day pumping, no sand trouble following plastic

There is an idea generally prevalent that if a sand sloughs, moves into a well and is actually produced with the fluid, a cavity is created adjacent to the well bore, which is proportionate in size to the volume of sand removed. If this were true it would follow that large volumes of plastic would be required to consolidate the sand in a given producing interval. Experience has shown, however, that if a sand, whether oil productive or not, lacks sufficient bonding material to make it competent under normal producing conditions, it is noncompetent throughout the entire reservoir. Consequently, when a sand adjacent to a well is produced it follows that more sand moves in to fill the vacated space, in a fashion similar to the movement of a fluid. Field data indicate that these so-called "cavities" do not exist. This is proved essentially by the fact that abnormal quantities of materials are not required to consolidate effectively a given productive interval. It is true, therefore, that, even though a considerable quantity of sand has been removed, effective consolidation of the formation can be secured.

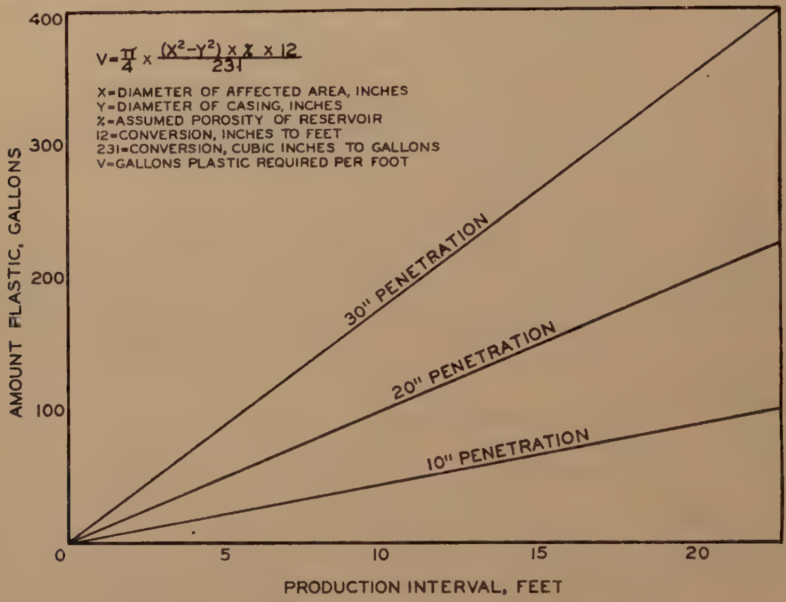

Fig 1—Data for calculating amount plastic required.

Assuming a porosity of 30 pct these curves indicate plastic gallonage requirements for a well with 7-in. casing. All volumes on the curves are *V* plus the casing volume of the affected section.

The amount of sand-consolidation plastic required for any job can be calculated readily if the diameter of the well bore, the desired depth of plastic penetration, the average porosity and the thickness of the producing section are known. The formula for making such calculations is given in Fig 1 along with data on the amount of plastic required for 10, 20 and 30 in. penetration over production intervals from 0 to 25 feet.

Methods of Application

In wells where the casing has been set and cemented in place on top of the sand, with a screen set through the sand, the customary practice is either to remove or to gun-perforate the screen before applying the plastic.

The actual operation of injecting sand-consolidation plastic into a formation is accomplished by the squeeze technique.[10]

In this method certain procedures are used to obtain distribution of the plastic across the completion interval. These include a special plug landing tool to control the placing of the plastic, a drillable or retrievable retainer to accomplish the "squeeze," and a predetermined length of perforated plastic or drillable metal tailpipe below the retainer. The tailpipe is used below the retainer to ensure even distribution of the injected fluid over the completion interval.

After this assembly is in place in the well, oil is pumped into the tubing in sufficient volume to displace the mud or other fluids from the tubing and from the casing, below the retainer. The retainer then is set and a feeding rate into the formation is established with oil. This is followed by the squeezing of the plastic into the formation. After the required setting time of the plastic has elapsed, the remaining plastic plug is drilled out, usually with a rock bit on a string of tubing, and the well is put on production.

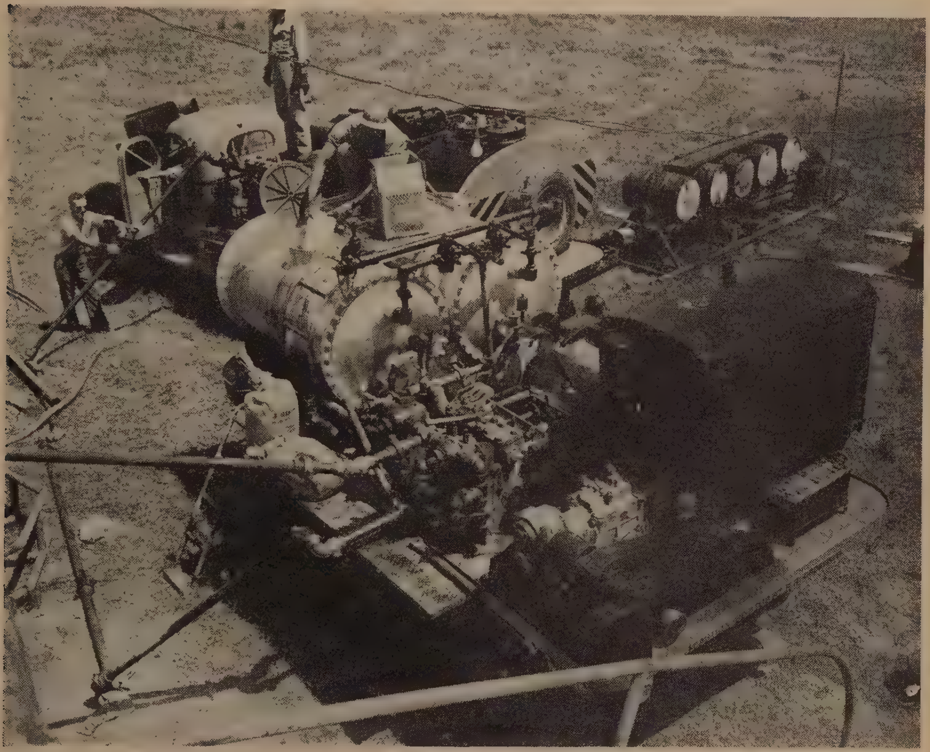

FIG 2—PUMP TRUCK WITH PROPORTIONING AND PLASTIC-TRANSPORTING TANKS.
Trailer carries motor-driven plastic mixers and plastic pump. Picture taken at a well near Houston, Texas.

If a retrievable retainer is used, it is set well above the perforated section, to assure its removal following application of the plastic. Where a drillable retainer is used the tubing is backed off and pulled from the well and both the retainer and tail pipe are drilled out at the same time as the hardened plastic plug.

The surface equipment used in this work was designed and built especially for the preparation and application of plastics to wells. A large tandem-drive truck carrying a motor-driven high-pressure, high-volume pump, also proportioning and plastic tanks, is used in conjunction with a large four-wheel trailer on which is mounted two 300-gal motor-driven plastic mixers and a specially designed triplex plastic pump. This type of equipment is illustrated in Fig 2.

The triplex pump on the truck is used for circulating, determining formation injection rates, displacing the plastic from the tubing and squeezing it into the formation. The mixers are required for necessary, thorough blending of the plastic and catalysts. The pump on the trailer unit is used to discharge the finished plastic from the mixers into the tubing.

Summary of Results

Since the introduction of the service, more than 150 wells have been given treatments with this type of plastic. Generally speaking, the results obtained have been encouraging. It is estimated that more than 80 pct of all the treatments made to date are successful. An analysis of the remaining 20 pct, classed as unsuccessful, indicate three major reasons for failure. These are: (1) lack of sufficient bottom-hole temperature; (2) lack of zone isolation; (3) improper conditioning of a zone that has produced large volumes of sand.

Table 1 contains pertinent data on 16 wells, typical of the results obtained in recent months. The wells listed have produced from 3 to 12 months since consolidation; five of the examples are from 9 to 12 months old, eight are from 6 to 9 months, and three are from 3 to 6 months old. They cover a wide range of formations, temperatures, depths and thicknesses of producing intervals. The temperatures vary between 110° and 180°F, with an average of 150°F; the thicknesses of the producing intervals range from 2 to 60 ft, the average being 15.5 ft; the plastic averages 165 gal per well, the maximum being 330 gal and the minimum 75 gallons.

Most of the treatments to date have been made on wells in which the producing zones did not exceed 5000 ft in depth, although some sands have been consolidated at depths less than 2000 ft and others at depths exceeding 9000 ft. The pressures required to inject the plastic into these sands have not been high when compared with pressures that frequently occur in squeeze cementing. The highest pressure encountered in this group of wells (Table 1) was 2500 psi, 1325 psi being the average for the tabulation.

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DISCUSSION

P. N. Weidner*—The paper prepared by Mr. Smith and Mr. Polk gives a very interesting summary of the work their company has done on consolidating incompetent sands with plastics. The possible value of consolidating plastics to the industry can hardly be overemphasized, since they should enable operators to recover millions of barrels of oil that could not be produced otherwise on account of sand trouble.

The work that has been done in developing the new consolidating plastics and placement techniques is very encouraging and the men who are doing this work are to be commended. Although this type of treatment of unconsolidated sands has been in use only a short time, it appears to be the most promising development in well-completion practice that has appeared in several years.

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P. Oldenburg*—The authors of this paper cite several successful applications of the use of plastic in consolidating loose sands. The following discussion will substantiate this fact.

The Cedar Point field, Chambers County, Texas, is producing from two different horizons; namely, the Miocene sand section and the Frio sand section. The Frio sand section is firmly consolidated and has not given any sand troubles. The Miocene sand section, however, consists of a series of loosely consolidated sands. At the present time, wells are producing from five separate sand zones within the Miocene formation. The first well to produce in the Miocene sand section was brought in in 1938. At that time, no knowledge was had as to the character of the sand. The well therefore was completed in a similar manner to the Frio wells already producing; i.e., 7-in. casing was cemented on top of the sand and a slotted liner was set through the sand section. In approximately one year from the date of completion the well sanded up. The well was reworked by underreaming the open hole and gravel-packing the section. The well was brought back on production and has given no further sand troubles.

The next three Miocene sand wells in the Cedar Point field were gravel-packed before completion. Experience had taught us by that time that the Miocene sand section consisted of unconsolidated sands, which needed special completion method in order that the wells would not sand up.

Although gravel-packing of the wells was necessary, it was at the same time expensive and required special tools and technique to obtain satisfactory results.

Since the introduction of the use of plastics in consolidating loose sand, six new Miocene sand wells have been drilled in the Cedar Point field, which have all been treated with plastic before completion. Of the six wells thus treated, five have been successful while one is still producing sand after its initial treatment. Since the first treatment was undertaken in March of this year, not sufficient time has elapsed to pass final judgment on the use of plastic to consolidate sands. However, it appears that the treatment of plastic for consolidating loose sands is a major step forward in the well-completion technique.

The method used in applying the plastic in Cedar Point field has varied among the six wells. In two wells, 7-in. casing was set immediately above the sand section and the entire face of the sand exposed to plastic treatment. For a 10-ft section of sand, as much as 265 gal of plastic was used, leaving a core of plastic in the well, which, after 48 hr, was drilled out, slotted liner run through the section and the well brought on production. In one well 7-in. casing was set through the sand section, then perforated 8 holes per foot and 150 gal of plastic was pumped through these perforations into the sand. After 36 hr the plastic left inside the 7-in. casing was drilled out, a slotted liner was run and the well put on production.

In the remaining three wells, the same procedure as the last example above was followed, a slotted liner was omitted in the well. All the wells have come in on natural flow after the plastic treatment, some without the necessity of swabbing and some by running the swab once or twice. Initially these wells produce approximately 120 bbl per 24 hr through 18-in. choke with tubing pressure averaging 550 lb/sq in.

We contribute the success of the plastic treatment in these Miocene sand wells largely to the fact that the permeability of the sands in their natural state ranges well above 1000 millidarcys. Thus, if there is 10 pct, 20 pct or even 50 pct reduction in the permeability due to the plastic treatment, the sands retain sufficient permeability to produce.

As mentioned before, sufficient time has not yet elapsed to say whether the use of the plastic is 100 pct successful in this type of sand. However, the fact remains that we are able to complete the wells without any sand troubles by a technique that is simple to execute, safe to carry out and with minimum loss of rig time. The cost of the treatment compares favorably with that of gravel-packing, considering all things, including the rig time, special tools and the technique involved in either process.

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A New Well-completion Technique

By Thomas S. West,* Member A.I.M.E.

(Chicago Meeting—February 1946)

Abstract

Completion and production data presented for three wells in the Oakville area of Live Oak County, Texas, which were completed near the gas-oil or water-oil contact, indicate that coning may not be as prevalent a cause of failure in such cases as is commonly assumed. Failure in the cases discussed is indicated to be due instead to: (1) erosion of the formation, (2) flowing out of mud filter cake, or (3) failure of the cement. An open-hole gravel-pack type of completion procedure is proposed for preventing failures of this kind by preventing movement of all solid material in the space in which completion is made. Various combinations of layers of gravel, sand, and cement are utilized for this purpose.

Experimental results and theoretical discussion as to the applicability of gravel pack completion are included.

Introduction

This paper is primarily a study of the reasons for failure of oil-well completions near the gas-oil or oil-water contact, and suggests a procedure for increasing the efficiency of this type of completion.

The value of improvement in completion effectiveness near the gas or water zone is not confined, however, to wells of relatively thin oil columns. Thick oil columns become thin as depletion progresses. It would seem to follow that the minimum distance from the gas or water zone at which completion can be made in a new well indicates the limit to which depletion may be carried in a well having an oil column of any initial magnitude.

Only four ways can be postulated in which high gas-oil or water-oil ratio can initially occur if the zone exposed for production is within the oil column:

1. Failure of the cementing material.
2. Vertical coning.
3. Failure along the boundary between the cement and the wall of the well.
4. Failure of the formation comprising the wall of the well.

Cementing materials such as portland cement and plastics have reached a high stage of development. Failures of this type are probably due almost always to extraneous causes such as mud contamination rather than to faulty cementing material.

Vertical coning can and obviously does occur. However, the usual occurrence of thin impermeable streaks in sand sections and the success with which open-hole drill-stem tests can be made near the gas-oil contact suggest that over-all effective vertical permeability, and in turn vertical coning, is less prevalent than frequently is assumed.

Much has been written on failure by flowing out of the mud filter cake between cementing material and the formation. A filter cake is always present if, prior to cementing, mud has come in contact with a permeable formation at pressures exceeding the pressure head of the fluid it contains. Mechanical methods are in use for removing filter cake during the cementing operation, which undoubtedly are of

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value.[1] Because of the rubber-like texture of filter cake as observed in wall-building testers, its removal by the scouring action of cement or by water pumped ahead of cement would seem doubtful. In any case, rather complete removal would appear necessary. A relatively small initial leakage path might be sufficient to cause ultimate failure.

FORMATION EROSION CAUSE OF FAILURE

The formation comprising the walls of the well seems to have received scant attention as a possible source of failure, even though failure of this type occurs frequently on drill-stem tests. Often little or no leakage past the test tool packer occurs during the first few minutes but after that leakage rapidly increases, as indicated by sinking of the mud level outside of the drill pipe. If such failure can occur with an expansible rubber packer, which is being pressed against the wall with considerable force, the tendency for failure undoubtedly would be much greater with a rigid material like cement.

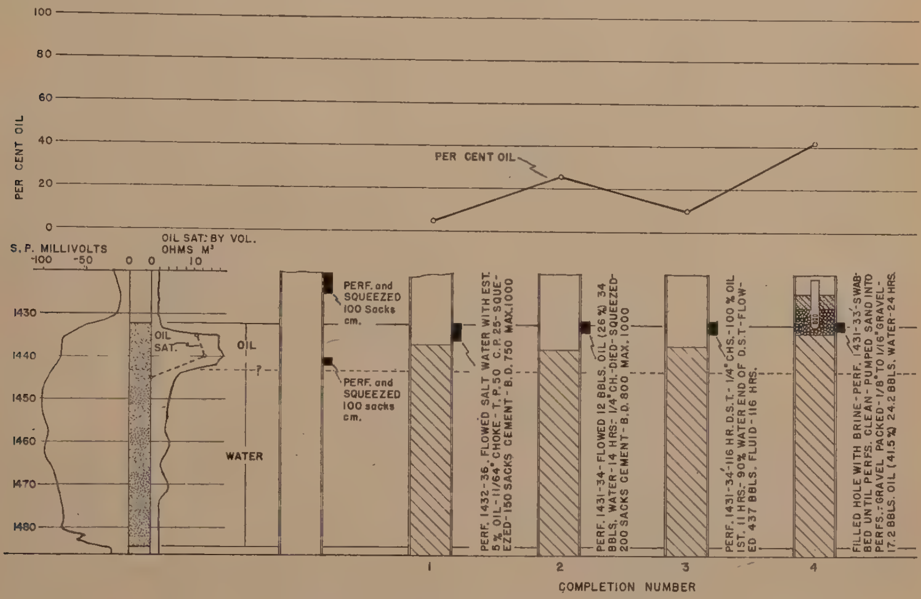

FIG. 1.—COMPLETION DATA ON 1400-FOOT COLE-SAND WELL.

The possibility that sand production might cause a cavity that ultimately would extend to the gas-oil or water-oil contact has not been adequately stressed. Since sand production is a result of fluid flow, it follows that any cavity produced will tend to extend in all directions from which fluid flow occurs. The occurrence of thin, impermeable layers will have little influence on the production of a cavity. It may be demonstrated mathematically that even a limestone or sandstone member one foot thick will rupture when an area 10 ft. in diameter, is unsupported on one side, if the pressure on the other side is greater by 80 lb. per sq. in. If the unsupported area is 5 ft. in diameter, failure is indicated to occur at 320 lb. per sq. in. Pressure at which failure occurs under these conditions will be much less for shale members, of course.

This calculation of pressure required for failure is based on the assumption that a circular plate fixed at the edges is approximated. The maximum stress in this case may be calculated from the following relation:

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[1] References are at the end of the paper.

$$S = \frac{3}{4}\frac{Pr^2}{T^2}$$

in which S is maximum stress; P is pressure in pounds per square inch; r, radius in inches; and T, thickness in inches.[2] Modulus of failure in flexure employed was 1500 lb. per sq. in. based on tests on limestone and sandstone by the Watertown Arsenal.[3]

The resistance of the formation to erosion is dependent both upon its strength and upon the pressure or fluid velocity to which it is subjected. Thus failure may occur in a relatively hard sand at a point at which the pressure gradient is high, as along the outer face of the cement between the gas and oil zones, even though this sand remains intact elsewhere.

Many failures appear to be a combination of failure along the face of the cementing material; for instance, flowing out of the filter cake and formation erosion. With this type of failure a small leakage path develops and is followed by enlargement of the resulting channel by erosion of the formation.

Completion Data

Fig. 1 shows completion data on a 1400-ft. Cole-sand well in Live Oak County, Texas. Water percentages are shown at 1-hr. intervals on a 5-day drill-stem test on casing perforations on this well (Fig. 2). The production of water-free oil during the first 11 hr. of this test definitely establishes that perforations were opposite sand that initially produced water-free oil. The existence of two sudden increments in water percentage (*A* and *B*, Fig. 2) indicate that at least one of these increments was due to causes other than coning since only one cone could have formed.

Fig. 3 is a curve showing water percentage plotted against rate of production on a replacement well, which was only 200 ft. from the well of Fig. 2. This well, which penetrated the producing sand only 2 ft., also initially produced water-free oil but developed a high water percentage after only 200 bbl. of oil had been produced. Extrapolation of the curve of Fig. 3 to zero rate of fluid production indicates 88 per cent water production. Inasmuch as some rate of production would exist at which water-free oil would be produced if water production were due to vertical coning[4] the existence of such coning seems disproved.

The early development of high water-oil ratio in a well that did not penetrate water-productive sand, by a mechanism other than vertical coning, seems definitely indicative of formation failure (sand production), bottom-water drive, or both. The history of this and an adjacent well is strongly suggestive of both the production of a cavity because of sand production, which ultimately extended to the water level, and bottom-water drive. Channeling caused by sand production seems established as at least a partial reason for high water-oil ratio, by the fact that water percentage was materially reduced (Fig. 1), by first squeezing sand through casing perforations to fill any cavity present, and then gravel packing inside of casing perforations to hold this as well as the producing sand in place.

Figs. 4, 5, and 6 show completion data on two substantially identical wells that were only 170 ft. apart. Data of Fig. 5 is on a replacement well that was drilled after the abandonment of the well of Fig. 4, because of excessive water production that could not be shut-off by squeezing.

A definite relation between high gas-oil ratio and distance between the gas zone and nearest perforation appears established by the data of Figs. 4 and 5. In these cases an impermeable layer was present between the gas and oil zones.

Notwithstanding, high gas-oil ratio developed five times out of the six cases in which the nearest perforation to the gas zone was 4 ft. or less. High gas-oil ratio because of vertical coning seems definitely eliminated in these cases by the presence of an impermeable layer.

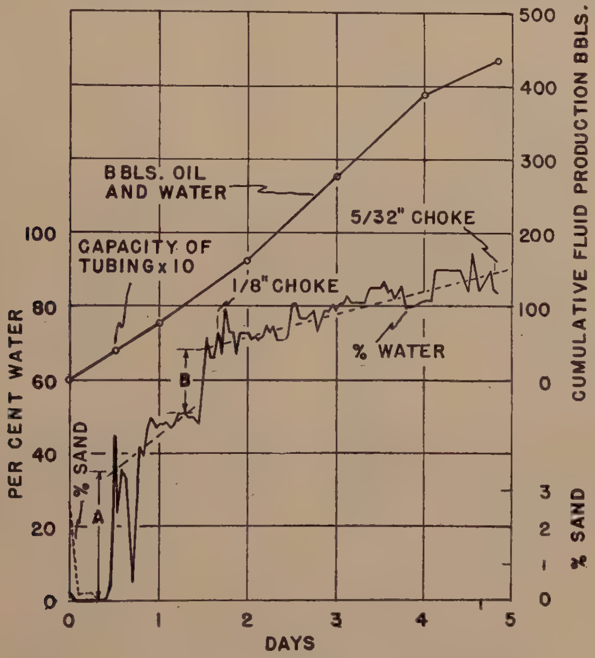

FIG. 2.—DRILL-STEM TEST ON CASING PERFORATIONS.

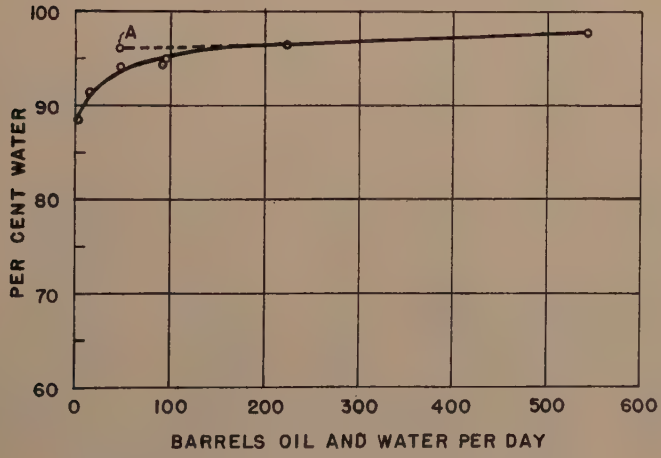

FIG. 3.—WATER PERCENTAGE VS. RATE OF PRODUCTION.

The production of a cavity that extended to the water level seems established in the case of Fig. 4. Water-free oil was produced initially. High water-oil ratio developed within 48 days, during which time 872 bbl. of oil was produced. The formation of a cavity is suggested by the fact that considerable sand production immediately preceded the development of high water-oil ratio. The possibility of the occurrence of edge-water encroachment is eliminated by the production history of the well of Fig. 5, a later and practically identical well only 170 ft. away. Not only was water-free oil produced initially in the latter, after the abandonment of the well of Fig. 4, but 4639 bbl. of oil was produced before an equally high water-oil ratio was reached.

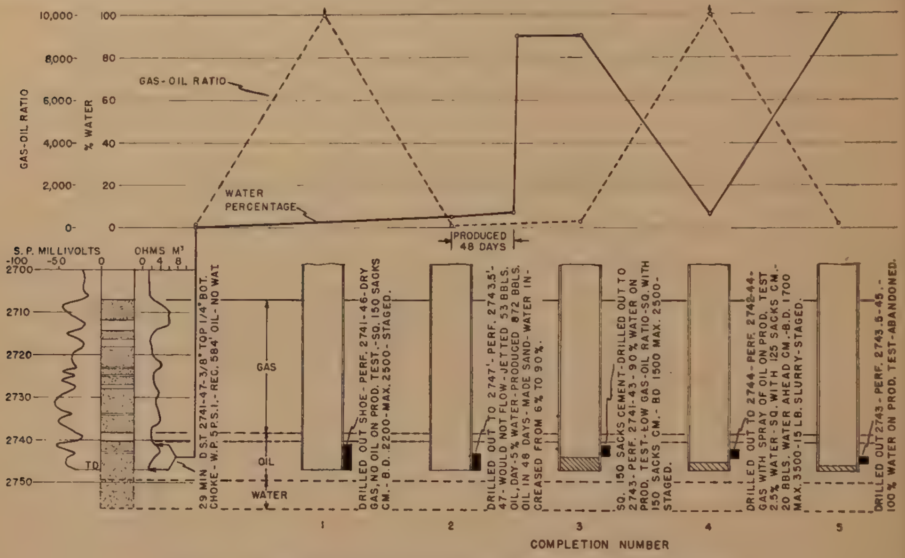

FIG. 4.—COMPLETION DATA ON WELL THAT WAS ABANDONED.

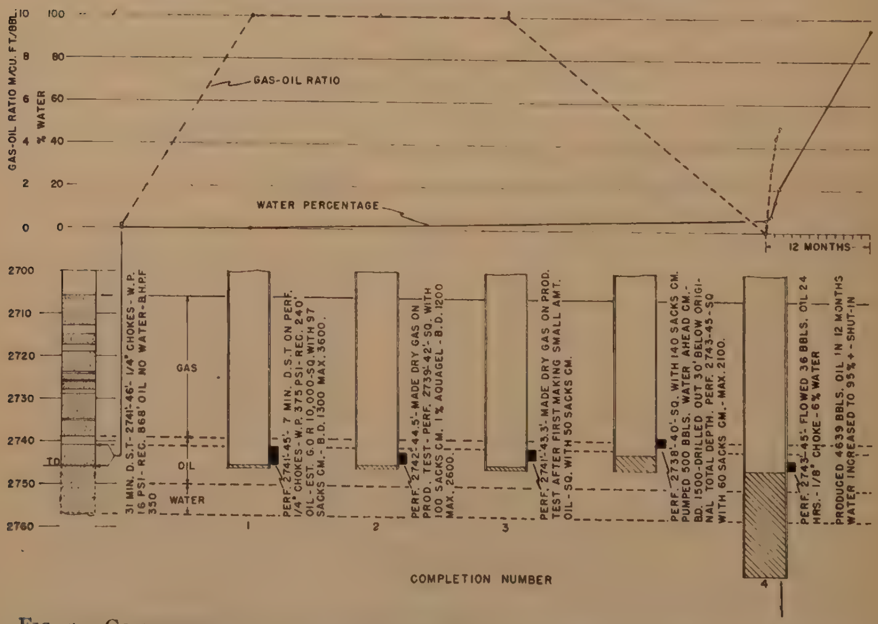

FIG. 5.—COMPLETION DATA ON REPLACEMENT WELL 170 FEET FROM WELL OF FIGURE 4.

Fig. 6 shows data that are strongly suggestive of failure by flowing out of the filter cake. In this figure working pressure across a ¼-in. top choke on drill-stem test in open hole is compared with that across a choke of the same size on a drill-stem test on casing perforations in approximately the same section. Working pressures were identical for the first 4 min. At the end of 5 min. working pressure was 74 lb. per sq. in. higher for the test on casing perforations. These data suggest that material of some kind flowed out at the end of 4 min. in the test on casing perforations, thereby providing a channel for gas flow.

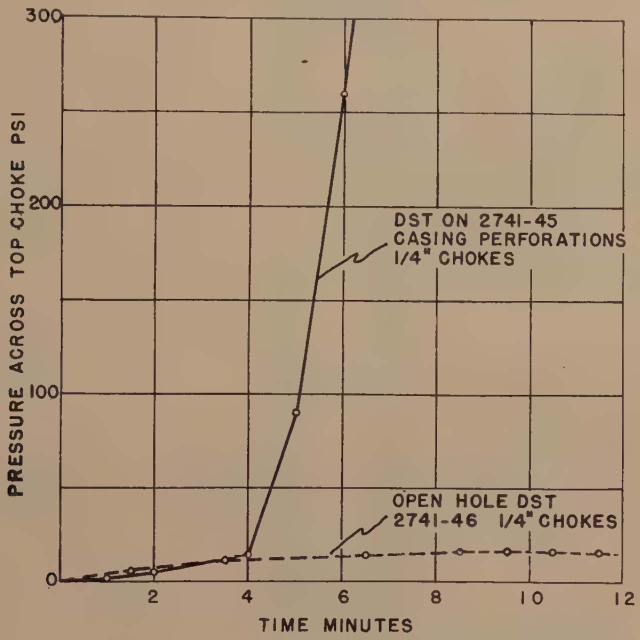

Fig. 6.—Data suggesting failure by flowing out of filter cake.

A consideration of the mechanism by which these failures occur indicates that except for vertical coning failure is always a result of the movement of solid material. For example, the flow of mud-contaminated cement sludge, the movement of filter cake or of sand or shale particles. The completion technique to be discussed later is based upon holding in the initial position sand, shale, mud, cement, sludge and any other solid material that might cause failure by flowing out. Such materials are held in place by various combinations of sand and gravel layers. The ability of drilling mud to form an impermeable filter cake on the face of a sand layer is also employed for obtaining a positive gas or water shut off.

New Completion Method

To prevent failures of types described the completion method shown by Fig. 7 was developed. The liner ordinarily is a 1½ to 2-in. pipe having the bottom end closed and milled or hacksaw-cut circumferential slots. These slots are of a width that will positively retain all gravel of the particle size employed. The liner material preferably is stainless steel or similar material having high resistance to corrosion. Because of scarcity of materials, usual grades of seamless steel tubing have

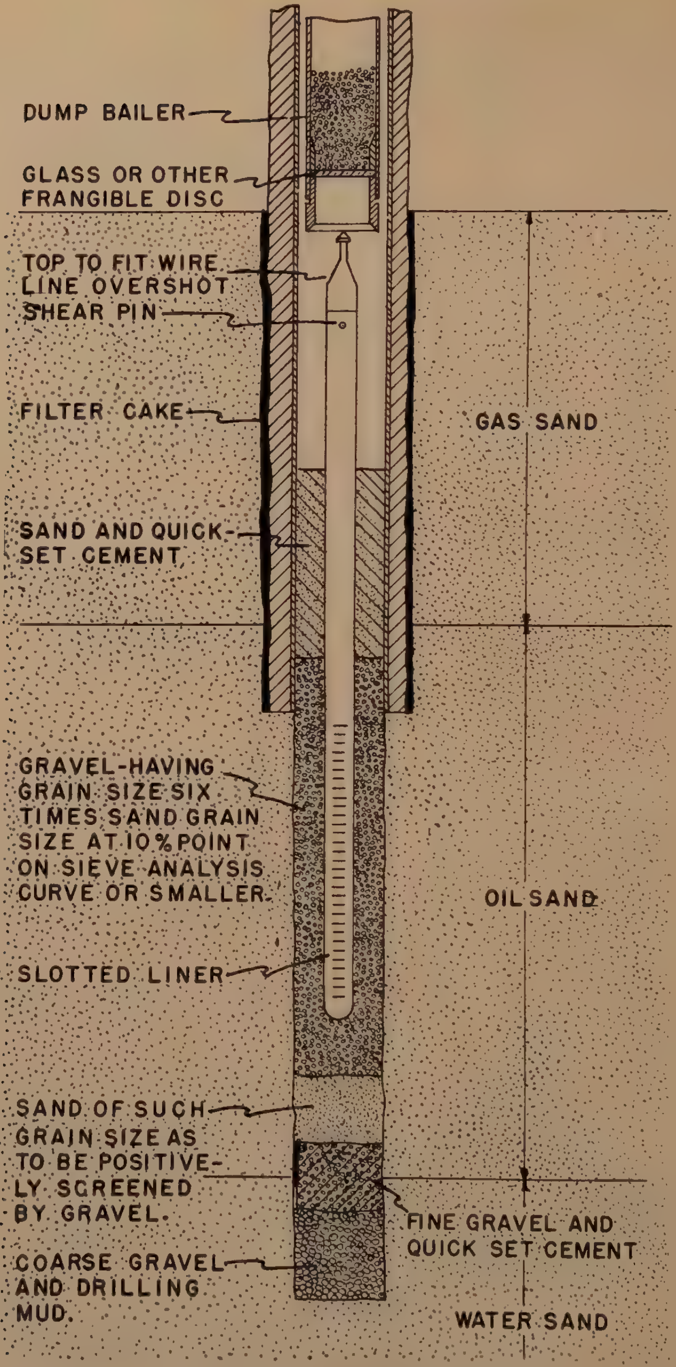
DUMP BAILER
GLASS OR OTHER FRANGIBLE DISC
TOP TO FIT WIRE LINE OVERSHOT
SHEAR PIN
FILTER CAKE
SAND AND QUICK-SET CEMENT
GAS SAND
GRAVEL-HAVING GRAIN SIZE SIX TIMES SAND GRAIN SIZE AT 10% POINT ON SIEVE ANALYSIS CURVE OR SMALLER.
OIL SAND
SLOTTED LINER
SAND OF SUCH GRAIN SIZE AS TO BE POSITIVELY SCREENED BY GRAVEL.
FINE GRAVEL AND QUICK SET CEMENT
COARSE GRAVEL AND DRILLING MUD.
WATER SAND

FIG. 7.—NEW COMPLETION METHOD.

thus far been used. A cap of drillable metal such as an aluminum alloy closes the upper end of the liner until the gravel, cement, and other materials are in place. This cap is held in place by a shear pin and is formed on top to permit engagement by an overshot, or similar tool, which is employed for lowering the liner to the bottom and for pulling off the cap when the cement overlying the gravel has set. This overshot usually is run on a wire line. All gravel, sand, cement, and other material is placed by dump bailer.

The most satisfactory type of dump bailer has been found to be one in which the bottom is closed by one or more plate glass (or plastic) disks (Fig. 7). When dumping on bottom a device is attached to the bailer to break the glass disk when the bottom of the hole is reached. When dumping material around the liner, the glass disk is broken by impact against the liner top when the bailer passes over it.

A small quantity of gravel usually is dumped on bottom before the liner is run, to avoid the possibility of the latter settling in loose sand to the level of the first slot. The liner is then run on a type of wire-line overshot that permits its release on bottom. The length of liner is sufficient to extend at least 10 ft. above the bottom of the casing. Gravel is then dumped in small batches until the desired level is reached. The "fill up" is checked after each run by observing the change in point of "pickup" of the bailer. The gravel is tamped after each dump by spudding the bailer. When the desired amount of gravel is in place, a mixture of quick-setting cement and sand is dumped on top of the gravel. The amount of cement mixture is sufficient to reach a level not closer than 2 or 3 ft. below the liner top. The function of the sand is to bridge the pore spaces of the gravel, thus preventing the entry of cement. After the cement has set, the top of solid cement is checked by running the bailer. If sufficient solid cement is present, the liner top is pulled off by engaging with the wire-line overshot and shearing the pin by an upward pull.

The sequence of layers shown below the gravel are employed if it is desired to plug back or to hold in place material of fine grain size, such as filter cake or shale. Obviously this sequence of layers in the reverse order can be placed around the liner and between the gravel pack and cement layer when it is desirable to exclude fine material from above or to shut off gas. The strictly essential element of this arrangement in addition to the gravel pack is the sand layer. This sand, of course, is of such grain size as to be held in place by the adjacent gravel. It is also preferably of very low permeability. These characteristics may be obtained by mixing material of fine particle size, such as aquagel, baroid or silt, with a sand that is coarse enough to be screened by the gravel. It has thus far been found quite difficult to secure such a mixture, which approaches zero permeability to gas. The layer of quick-setting cement and coarse gravel saturated with drilling mud, or other fluid having fine solid particles in suspension, are provided therefore to more positively ensure an impermeable plug. With this arrangement any path for flow that develops through the cement plug results in a flow of drilling mud against the sand layer. This flow deposits an impermeable filter cake. Furthermore, if a break in the filter cake thus deposited should occur because of a slight movement of the sand layer, this break would be sealed immediately by a new deposition of filter cake. Some movement conceivably could occur with any type of plug because of temperature changes. In addition, the small change in volume of a sand layer might occur because of compaction or a slight invasion of sand into the gravel pack. This arrangement is thus seen to be automatically self-sealing. Any flow that develops continually decreases. As previously stated, any such flow tends to become progressively greater as a result of erosion when cementing material alone is used.

EXPERIMENTAL VERIFICATION

The effectiveness of plugs of this type have been experimentally investigated by the author. No cement layer was employed in these experiments. The gravel, sand, and coarse gravel and mud layers were packed in a cell that was similar to that of Fig. 8 except that it was made from 5½-in. o.d. well casing instead of 2-in. pipe. These experiments indicate complete sealing action through the pressure range investigated. This range was 0 to 2600 lb. per sq. in. The pressure fluid was gas from a gas-distillate well having a casing pressure of 2600 lb. per sq. in. However, by filling the space in the cell above the coarse gravel layer with water, the sealing action with respect to water was also determined. The filter cake deposited with the higher pressures had a texture and appearance almost identical with that of shale. In these experiments the gravel, sand, and coarse gravel and mud layers were dumped with the cell filled with water in an almost exact duplication of the procedure followed in depositing these materials with a dump bailer in an actual well in application to the exclusion of gas.

Muskat[5] has shown mathematically that even a sand column having higher permeability than the producing formation has a very pronounced plugging action, which may be almost as effective as a cement plug. This conclusion would presume, of course, that the velocity of fluid flow would not be great enough to lift the sand or that it be held in place by some means, such as the gravel pack of Fig. 7. Since the use of sand alone as a plug is indicated as so effective, the question arises as to whether the additional complexity of employing the illustrated layers of cement and the coarse gravel and mud mixture is justified in practice. However, a permeable sand plug would always result in some flow. Although the volume of gas or water flow might be negligible in proportion to oil in a uniform sand, this might not be true if oil production were from a relatively nonpermeable section of the sand. It is quite likely that use of a sand plug or a combination of sand with cement or plastic plugs might also prove satisfactory in many cases. However, in an operation as expensive as a deep well, there seems to be little excuse for using a procedure that may be satisfactory on the average in preference to the best possible method, provided the cost is not significantly greater.

The average time required for the operation is approximately 6 hr. if a cement that sets in 2 hr. is employed. This is the time interval between the running of the liner and the recovery of the liner top.

Preparation of Well

The usual practice in preparation of the well for gravel packing has been first to run tubing, then replace the drilling mud with water or brine, dependent upon the hydrostatic head required to exceed bottom-hole pressure. Then the well is swabbed (or bailed, if pressure is low) until there is some fluid flow from the sand. The purpose of this flow is the removal of filter cake. (Filter cake has been removed in one case by underreaming with brine as a circulating fluid. This result may also be secured by use of wall scratchers, which may be run on a wire line.) If the well has been swabbed in, it is killed with water or brine and the tubing is pulled. All sand and other loose material is removed by bailing. For pressures requiring a fluid weighing more than 10 lb. per gallon, a ferric sulphate solution may be employed. Commercial grades of ferric sulphate are available that permit the relatively economical preparation of solutions weighing as much as 11 lb. per gallon with a theoretical maximum weight of 14 lb. per gallon.

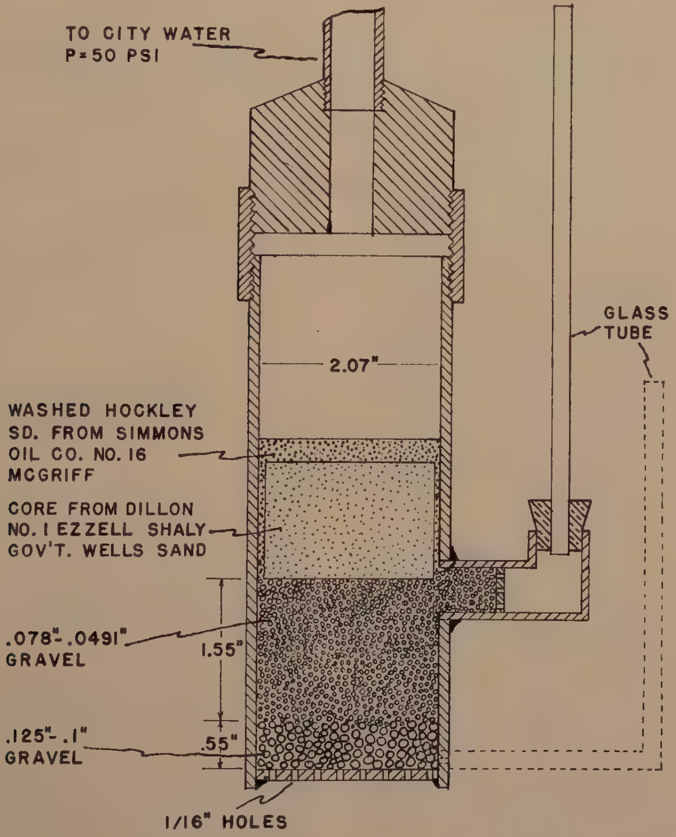
TO CITY WATER
P=50 PSI
GLASS TUBE
2.07"
WASHED HOCKLEY SD. FROM SIMMONS OIL CO. NO. 16 MCGRIFF
CORE FROM DILLON NO. 1 EZZELL SHALY GOV'T. WELLS SAND
.078"-.0491" GRAVEL
1.55"
.125"-.1" GRAVEL
.55"
1/16" HOLES

FIG. 8.—APPARATUS FOR DETERMINING EFFECTIVENESS OF SCREENING SHALY OR SILTY SANDS.

It has also been demonstrated experimentally that gravel may be placed satisfactorily by use of a drilling fluid composed of brine, a starch solution and a small amount of bentonitic material.[6] This fluid may be "spotted" on bottom and to a height 100 ft. or more above the sand. The original mud filter cake may be then removed by means of wall scratchers and bailer, permitting the formation of a new filter cake by the starch suspension. This type of fluid has a very low water loss and forms a filter cake of negligible thickness that will flow back readily through the gravel pack upon completion. Starch filter cakes may be removed by hydrolysis to glucose by acids or starch-splitting enzymes. Such enzymes are contained in commercial products such as Pancreatin or may be produced *in situ* by bacterial action if bottom-hole temperature and pH of mud are satisfactory. However, in view of the ease with which such a starch filter cake flows back through the gravel pack, employment of a special procedure for its removal would seldom be required in practice.

Gravel-packed liners of the type just described may be removed easily by washing over with a rotary shoe and then retrieving the liner by means of an overshot, which may be run either on tubing or drill pipe or on a wire line.

If the thickness of the cement layer that holds the gravel in place does not exceed 5 to 10 ft., the liner may be pulled easily by engaging with a fishing tool run on a wire line and jarring upward. It is also possible usually to pull liners under these conditions by repeated direct pull with usual wire-line workover equipment without the use of jars.

Determining Effectiveness of Screening

To gain information as to whether the relatively shaly sands of the Jackson section could be successfully gravel-packed using gravel small enough to screen the sand under high-pressure conditions, a number of laboratory experiments were performed. It was known that small gravel could be used successfully to screen relatively clean sands under high-pressure conditions. Data were available also on a large number of Jackson-sand wells in Duval and Webb Counties, Texas, which had been successfully gravel-packed with pea gravel (approximately ¼-in. or larger). The gravel in these cases, however, was too large to screen the sand, particularly under high pressures; the principal function of the gravel being that of prevention of caving of the walls rather than screening.

The apparatus employed for determining the effectiveness of screening shaly or silty sands is that illustrated by Fig. 8. Tests were run under various pressure and flow conditions using oil having a gravity of 20° Bé. and a Saybolt viscosity of 180 sec. Various oil sands were used on these tests; the screen analyses are given by Table 1.

It was found that gravel size required for approximating complete prevention of sand production had an average particle size about six times the sand grain size at the 10 per cent point on a sieve-analysis curve: for example, sand from Simmons Oil Company's No. 16 McGriff was screened by a gravel passing a 10-mesh (0.0787-in. opening) screen, which was retained on a 16-mesh screen (0.0469-in. opening). Gravel having these particle-size relations were indicated by these tests to be equally effective in screening relatively shaly sands.

TABLE 1.—*Screen Analyses of Sands*

Screen, Mesh	Opening, In.	Cumulative Percentage by Weight				
		H. Coquat 1-A, West 1440–41, Core Cole Sand	Simmons Oil 16, McGriff 2131–32, Clean-out Sample, Hockley Sand	Dirks and Coquat 2-A, Harris 3830–31, Core Pettus Sand	Dillon No. 1 Ezell 1042–48, Core Govt. Wells Sand	LeFevre 1, Martinez 1763–67, Clean-out Sample, Cole Sand
20	0.0331	0	0	0	0	0.3
30	0.0232	0.3	0.35	0	0	0.3
40	0.0165	0.3	1.6	0	0	0.5
50	0.0117	0.6	8.0	0	1.2	0.8
60	0.0098	2.5	18.4	0	6.0	2.8
100	0.0059	55.8	46.4	0	53.0	85.7
140	0.0041	89.1	67.4	23.3	69.0	94.3
200	0.0029	95.9	92.9	79.8	71.8	99.5
Pan		100	100	100	100	100

Mechanism of Plugging Screens

A discovery of interest in the study of the mechanism involved in the plugging of gravel packs and other screens was noted in conducting the experiments just described. It was observed that oil from a stock tank could not be made to flow continuously through the sand from which it was originally produced even with pressure greater than the bottom-hole pressure. After an initial period of flow consistent with sand permeability, pressure differential, and other factors, flow gradually diminished, and stopped completely after 15 or 20 min. It was then possible to restore the initial flow conditions by removing the top ⅛ to ¼ in. of the sand layer. The plugging material was found to be a fine silt, which remained in suspension in the oil and which apparently was present in the sand. This silt apparently was liberated by caving and disintegration of sand as a result of oil flow. This material could not have flowed through the pore spaces of the sand, since, as just demonstrated, the particle size was sufficient to plug the sand from which it originated. It would seem to follow from these data that any procedure for screening silty sands in which space is present between the screen and the producing formation would ultimately plug unless some sand production were permitted. Plugging would occur, of course, by accumulation of sand around the screen, which in turn would be plugged by material of fine particle size liberated by the disintegration of the sand. It is a matter of common observation, particularly along the Jackson trend, that the use of screening methods of this type, which completely screen the sand, almost invariably plug. This observation applies to conventional screens, gravel-prepacked liners, and usually to gravel packing inside of casing perforations. It will be appreciated that the latter becomes the equivalent of a gravel-prepacked liner if space is present outside the casing as a result of sand production. These data seem to indicate conclusively that completely filling the space to be gravel-packed, thereby preventing the liberation of silt because of the disintegration of sand, will permit the use of gravel sufficiently small to provide complete screening action without danger of plugging, regardless of the character of the sand.

This conclusion may be reached also by an entirely different line of reasoning. Flow of the oil or other fluid produced through a sand does not cause plugging of the pore spaces of this sand; otherwise, fluid would not flow into the well from the surrounding area and production would cease. Gravel packing may then be regarded as simply replacing the sand removed by drilling by a sand of slightly larger particle size, which can be completely screened but which is too small to permit the inflow of the surrounding sand. No possibility of plugging by a material that would pass through the pore spaces of the sand would therefore seem possible, inasmuch as the size of the pore spaces in the gravel pack will be the larger. Since the chief possibility of plugging or reduced permeability is the infiltration of sand into the gravel pack, the use of gravel of smaller particle size, or even coarse sand, would seem to be indicated in many cases. Frequently the problem is whether or not a successful completion can be made by any means. As will be shown, the use of even a very small gravel leads to a relatively small decrease in the rate of production under usual conditions of application.

Experimental Screening of Shaly Sands

The possibility that the shale content of shaly sands might ultimately soften by the action of water and flow into and plug the gravel pack was also investigated experimentally. Fig. 8 shows the apparatus employed in this study. Two very shaly oil-sand cores were tested. The core was shaved down until it had an outside diameter approximately $\frac{1}{16}$ in. less than the inside diameter of the cell. Gravel was placed in the bottom part of the cell as illustrated. The core was placed on top of the gravel and in direct contact with it. The $\frac{1}{32}$-in. annular space between the wall of the cell and the core was filled with the designated washed oil sand and a layer of this sand was placed over the upper end of the core. It is apparent that this arrangement approximated the frequently encountered condition of permeable sand streaks between shale or shaly sand layers. This apparatus was connected to a city water system having a pressure of approximately 50 lb. per sq. in. Tap water has been flowed continuously through two cells of this type for the past seven months and this experiment is still in progress. Measurement of rate of fluid flow and pressure drop across the gravel-pack section was made at intervals of about one week. Originally this apparatus was intended for a purely qualitative determination. After seven months operation a second connection for pressure measurement was made at the top of the perforated plate, to permit the measurement of pressure drop across the gravel pack without including drop through perforations. The permeability of the gravel after seven months as determined by water flow was 17 darcys (17,000 millidarcys). Since no initial permeability measurement was made, it was not possible to determine directly variation of permeability. The permeability of Jackson sands is seldom more than 2500 md. and usually is below 1000 md. with measurements by air on dried samples. The permeability of this gravel therefore was large in proportion to that of sands for which it was intended. As will be demonstrated, the productivity of a well packed with gravel of this permeability should be approximately the same as that of an open hole completion, for usual conditions of application.

Equation for Flow

Determination of the relation between the measured pressure drop and rate of flow for various rates resulted in the following approximate equation* for flow:

$$Q = K\sqrt{h}$$

in which Q is the flow in cubic centimeters per second; h, the head in centimeters; and K, a constant that depended upon the permeability of the gravel pack and the size and degree of plugging of the perforations. It was also found that K was a constant for a series of measurements for different rates of flow if all measurements were taken over a period of three or four hours. However, when measurements were taken at intervals of one week, K was found to increase uniformly as the rate of flow increased. This relation of K to rate of flow was attributed to an influence of water velocity on the formation of rust and other corrosion and upon the formation of iron hydroxide by bacterial action. Accordingly, only values at which the rate of flow was approximately the same have been used in plotting the curves of Fig. 9. The rate of flow for which data are shown is 1 c.c. per second. Values of K have been corrected to this rate by use of the relation between K and rate of flow as determined for each cell. Except for the portion of the curves that are shown by dotted lines, the correction applied was small. To minimize the influence of rust and iron hydroxide, 37 per cent HCl was flowed through each cell at the end of 5 and 7 months. Since neither the sand nor gravel reacted with HCl, and since the contact of this acid with the iron walls of the cell was of only about 10 min. duration, no influence from the acid other than removal of corrosion, iron hydroxide and the killing of bacteria seems likely.

As will be noted in Fig. 9, the resistance to flow, including that of perforations, was approximately constant in the core from Dirks Brothers and Henderson Coquat No. 2-A Harris. This well is in the Toro Creek (West Tuleta) field of Bee County, Texas. The core was from the top of the Pettus sand at a depth of 3830–3831 ft. The Pettus sand contains much bentonitic material in this area. Exposure of this sand to water is believed by many to result frequently in plugging of the sand because of softening of this material. Evidently no such plugging action occurred in connection with the gravel pack. A screen analysis of this sand is given in Table 1.

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* The equation for flow resulting from various sets of data ranged from $Q = Kh^{0.61}$ to $Q = Kh^{0.68}$.

The value of K showed more variation for the core from Earl Dillon's No. 1 Ezzell.* The values of K as shown in Fig. 9 first decreased about 55 per cent and then remained approximately constant at this level during the remainder of the experiment. However, due to a smaller annular space between the core and wall of the cell, the rate of flow varied more as a result of the plugging action of iron hydroxide, rust, scale, and other debris, on the upper surface of the sand. The initial flow values were at a somewhat higher rate, requiring a relatively large correction for velocity of flow for this part. Some of the apparent increase in over-all flow resistance of the gravel pack and perforations may be a result of inaccuracy of the correction factor for high rates of flow. Table 1 gives a screen analysis of a sand sample one foot deeper and somewhat less shaly than that used in the experiment just described.

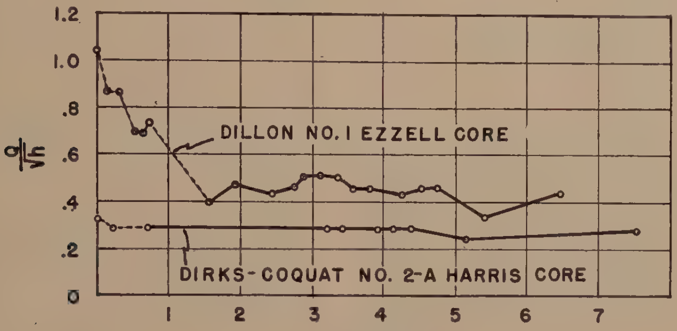

FIG.—9. DATA ON RATE OF FLOW.

Effect of Gravel Packs on Productivity

The influence of a gravel pack upon the rate of fluid production has been investigated experimentally by Hill;[7] Muskat[8] has developed a formula that is applicable to this problem.

For the laminar flow of a homogeneous fluid through an isotropic porous medium, Muskat[8] has shown the following relation to exist:

$$Q = \frac{2\pi K_g(P_e - P_w)\frac{h}{U}}{\log_e \frac{r_0}{r_w} + \frac{K_g}{K_f}\log_e \frac{r_e}{r_0}}$$

This formula may also be put in the following form:

$$\frac{Q}{Q_0} = \frac{\frac{K_g}{K_f}\log_e \frac{r_e}{r_w}}{\log_e \frac{r_0}{r_w} + \frac{k_g}{k_f}\log_e \frac{r_e}{r_0}}$$

Where:

Q = flow into the well in milliliters per second per centimeter of sand, with the space between the liner and the face of the sand filled with material having greater permeability than the producing sand.

Q_0 = flow into the well if the space between the liner and the face of the sand is filled with material having the same permeability as the sand.

K_g = permeability of the gravel, darcys.

K_f = permeability of the producing sand, darcys.

r_e = the external reservoir radius, ft.

r_w = the outside radius of liner, ft.

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* This well is in the South Calliham field of McMullen County. This core was from the Government Wells sand and from a depth of 1041 to 1041½ feet.

r_0 = the radius of the external boundary of the gravel, ft.
h = the sand thickness, cm.
P_e = the reservoir pressure at the outer boundary, atmospheres.
P_w = the reservoir pressure at the well atmospheres.
U = the viscosity, centipoise.

By use of the last formula, it may be shown that for a 2-in. o.d. liner in a 6-in. hole and a sand permeability of 1000 md.:

1. Packing the 2-in. annular space between the liner and the face of sand with a gravel having a permeability of 17,000 md. increases the rate of production by 14.5 per cent relative to that if this space is filled with the producing sand (1000 md. sand).
2. Pulling the liner and producing from the open hole increases the rate of production by only 0.97 per cent, or approximately 1 per cent over that obtained with a 17,000-md. gravel pack.
3. Producing from the open hole results in only a 15.6 per cent increase over that obtained with the annular space around the liner filled with the producing sand (1000 md.).

The relative pressure drops across the sand and gravel sections of the cell of Fig. 8 at the time the previously described permeabilities measurement was made indicated that for a constant water pressure only a 0.5 per cent increase in rate of flow would result from the complete removal of the gravel pack. The average permeability to water of the sand section in this case was approximately 70 millidarcys.

Hill[7] has shown experimentally that the permeability of a gravel pack using a relatively large gravel size may be considerably less than that of a much finer gravel because of sand infiltration. Hill's experiments indicate that a gravel having a particle size approximately six times that of the sand grain at the 10 per cent point on the sieve-analysis curve results in a gravel pack of maximum permeability. It is of interest to note that this relation between gravel and sand grain size is the same as that at which complete prevention of sand production was observed to occur in experiments by the author.

Earl Dillon's No. 1 Ezzell, which was the source of one of the cores used in the experiment shown by Fig. 8, was completed as an oil well in this sand. An attempt was made to produce this well prior to gravel packing. The result was four clean-out jobs within two months. The rate of oil production indicated during the relatively short periods during which this well was on production was 5 bbl. per day by pumping. This well was then gravel-packed, using the procedure illustrated by Fig. 7 without the bottom plug. Gravel size was 10 to 16-mesh (0.0787 to 0.0469 in.). The liner size was 1.9 in. o.d. An identical production test after gravel packing resulted in the same daily oil production. After six months, oil production has shown no decrease. As indicated by the sieve analysis, this is a very shaly sand. In addition, streaks of shale having little or no sand content are present in the section gravel-packed. This well also produces some salt water.

APPLICATION TO WELLS

Seven wells have been gravel-packed by this procedure; all but two of them being in fields in which all previous efforts at successful completion had failed. The two exceptions are on the Dillon Ezzell lease, in the South Calliham field, one of which has been described. The plug-back procedure illustrated by Fig. 7 has been applied in one well, a successful plug-back having been obtained. This was in an unconsolidated sand in which all other efforts at plugging back had failed. In no one of the five wells in which gravel was placed in the open hole by the procedure of Fig. 7 has plugging of the gravel pack occurred or evidence of reduced permeability been noted.

This procedure was used inside casing perforations in two wells. In one of these, Sid Katz No. 3 Martinez in the LeFevre field, Jim Hogg County, the gravel pack plugged after one week. This well had produced a considerable amount of sand prior to gravel packing, therefore unfilled space was present outside the casing, making it the equivalent of a prepacked liner. As evidence of the accuracy of this conclusion, the placing of the same type of gravel pack in the same sand in the open hole in Frank LeFevre's No. 1 Martinez, 1320 ft. north of the other well, led to a successful completion. This gravel pack had given no evidence of plugging after six months of production. Prior to gravel packing, this well had repeatedly sanded up when producing through a 0.012-in. slot, wire-wrapped screen. The use of the same size of gravel in a prepacked liner on an offset well caused plugging of the gravel within approximately one week. These data seem to verify the previously stated conclusion that the filling of all space in the section gravel-packed is an essential condition if gravel sufficiently fine to positively screen the sand is employed in silty sand sections.

The other case of application of this procedure inside of casing perforations is that shown by the fourth completion of Fig. 1, which was successful. As indicated, three attempts at completion by squeezing had failed and this well had been abandoned and a replacement well drilled. Partly as a test of the applicability of gravel-pack completion under these rather severe conditions, this well was recompleted as shown as Henderson Coquat No. 1 Albert West. Cement was first drilled out to the original depth using 9.8 lb. per gal. brine to control the relatively high bottom-hole pressure. Eighteen ⅝-in. gun perforations were made opposite the top 2 ft. of sand. Tubing swab was then run until flow from the sand cleaned the perforations. The well was then killed with brine and washed sand, from Simmons Oil Company's No. 16 McGriff (Table 1), dumped on bottom and then washed through the perforations by brine pumped into the oil sand. The function of this sand was to fill any space present behind the casing and the perforations with sand. The latter was to prevent any cement sludge or mud present behind the casing from flowing into and plugging the gravel pack. The filling of the perforations with sand obviously reduced the rate of fluid production, but productivity was in this case considered of secondary importance. The primary question was whether a successful completion of any type was possible. Gravel was then dumped until the casing was filled to a point above the top perforation. A 1.9-in. o.d. liner having ⅓₂-in. slots in the bottom 5 ft. was then run and the gravel-packing operation was completed as shown by Fig. 1. Gravel size was 0.125 to 0.05 inch.

A production test after this well had produced approximately the same total amount of oil as was produced on the previous completion yielded 17.2 bbl. of oil and 24.2 bbl. of salt water in 24 hr., this being a water percentage of 58.5. The best 24-hr. production test on any previous completion was 7 bbl. of oil plus 90 per cent salt water. This well has been on production for slightly over a year without evidence of plugging or decreased permeability of the gravel pack.

Evidently, the combination of gravel and sand packing reduced water production either by filling existing channels to the water level with sand or preventing their formation after squeezing. It is not to be expected, of course, that the filling of channels to the water level with clean permeable sand would entirely shut off water. It is also unlikely that all channels behind the casing could be filled with sand by washing sand through the perforations. The result sought and apparently realized in this case was the reduction of water production rather than a complete shutoff. The application of the plugging procedure shown in Fig. 7 would have required the milling out of the casing in the sand section. At the time of this completion no economical and successful method of milling out casing was known to exist. Such a method is available now, however, in most oil-producing areas, and has been used successfully in removing casing from the sand section of old wells for gravel-pack completions.[9]

Henderson Coquat No. 1 Albert West is the only successful completion in the Kittie field to date (January 1946).

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Related Trends in Future Domestic and Foreign Petroleum Operations

By Howard W. Page*

(Chicago Meeting, February 1946)

Abstract

Petroleum requirements since V-J day have been appreciably higher than predicted. Foreign operations now exceed maximum wartime levels by about 14 per cent. Domestic operations since V-J day have averaged 92 per cent of the wartime peak. In spite of maximum foreign refinery runs, large exports of all products, except residual fuel oil, are necessary to meet foreign demand.

During the next few years it is expected that foreign operations will continue at capacity, including new installations, but that, because of increases in foreign demand, exports will continue at about their present level. Domestic operations will increase during this period and crude production probably will exceed maximum efficient rates.

Even after 10 years some exports probably will be required, but eventually these will be supplanted by increased output of foreign refineries, except for small tributary exports. The increase in domestic requirements will exceed the decline in exports. Unless findings of crude oil exceed present expectations, the increasing demand will be met by increased imports and synthetic methods—such as the Hydrocarbon Synthesis Process for conversion of natural gas and coal to gasoline and distillates. Catalytic cracking installations will increase as crude availability decreases. This will help to meet the increasing demand for gasoline but will intensify the domestic shortage of residual fuel oil. Eventually larger imports will be required to satisfy the demand for this product.

Introduction

Under the pressure of the wartime period, there was time only occasionally to look ahead in anticipation of what the postwar era held for the petroleum industry. Perhaps the general expectation was that a rather pronounced decline in the level of industry petroleum operations would take place shortly after the end of the war, with the impact felt mainly on the economy of the United States. It is of interest now, nine months after V-J day, to take inventory of the near-term situation and see what significant forces are at work. With this as a starting point, it should be possible to engage in something more satisfactory than pure speculation concerning trends in the immediate future and 10 to 20 years ahead.

Present and Near-term Situation

During the nine-month period following V-J day, *foreign* crude oil production and refinery operations have actually increased substantially. These activities were at maximum capacity on V-J day but the continuation of drilling programs, the completion of new and rehabilitated refineries and of transportation facilities during the past nine months have increased the foreign capacity. This added capacity has been fully utilized. Foreign crude oil production in May 1946 is about 14 per cent higher than during July 1945 and refining operations some 12 per cent higher.

During the same period there has been a falling off in similar activities within the

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United States, averaging about 7 and 9 per cent, respectively, from the peak reached in July 1945. This is a smaller decline than was generally anticipated.

Projections for the remainder of 1946 indicate a continuation of this situation, namely, foreign operations remaining at maximum capacity with possible small increases resulting from new rehabilitations and domestic operations maintained at levels about equal to the average since V-J day.

In order to arrive at a sound basis for projection of future trends, it is essential to appreciate the reasons for the present situation.

Relative Requirements for Individual Products Most Important Factor in Present Situation

Upon termination of the war, the greatest change in product requirements world-wide occurred in gasoline. The armed services canceled practically all purchases of aviation gasoline, as well as substantial amounts of motor gasoline. It is of interest that this reduction was about equal in volume to the rationed gasoline consumption of all passenger cars in the United States. The increase in civilian gasoline consumption, resulting from elimination of controls, was not sufficient, however, to overcome the decrease in military purchases.

It was inevitable that the effect of the entire net decrease in gasoline requirements would be felt in the United States. Foreign consumers, in general, are inclined to procure supplies from foreign sources before coming to the U.S., mainly because:

1. A lower requirement for dollar expenditure is incurred, which in most countries today is considered more important than the cost in local currency, and,
2. A decrease in foreign gasoline production would cause a disproportionate loss in residual fuel-oil production, leading, in turn, to a world-wide shortage of the latter product.

This has the effect of making the United States a marginal supplier of gasoline to most foreign areas. However, foreign refineries, though operated at maximum capacity, cannot produce enough gasoline to meet all foreign requirements, even with the war ended. Inasmuch as this situation is expected to continue for several years, exports from the U.S. will also continue, although at a level below wartime needs. A similar situation exists with regard to kerosine, distillates, and lubricating oils.

In view of the factors favoring a foreign source of supply for foreign consumption, there appears to be only one reason why new and existing foreign facilities would not operate at maximum capacity for the next few years. That reason would be a restricted outlet for residual fuel oil. At the present time, foreign production of residual fuel oil is in excess of the foreign demand, but this excess is barely sufficient to meet the United States deficit. It is expected that there will be a slight decline in residual requirements during the next 6 to 9 months, which might possibly bring about a slight oversupply world-wide when operating foreign refineries at full capacity. Foreign operations might, therefore, decline slightly when and if residual fuel-oil outlet becomes limiting. Notwithstanding this possibility, the best guess is that full foreign production throughout 1946 will no more than cover the residual fuel requirements.

It is important to note, however, that about 100,000 bbl. daily of present foreign residual production is marginal; that is, because of the crude oils and equipment utilized, production of residual fuel oil in foreign refineries can be reduced approximately this amount with only a negligible effect on the production of light products. Thus it appears that for a considerable time in the future the world requirements and supplies of residual fuel can to this extent be balanced independently, without affecting yields of other products. This is an important consideration in estimating the petroleum situation of the United States and simplifies considerably the problem of balancing world-wide requirements and available supplies of individual petroleum products.

Why Domestic Refining Operations Cannot be Expected to Balance Domestic Demand for Residual Fuel Oil

Domestic refinery operations are expected to be based on outlet for gasoline, kerosine, distillates, lubricating oils and specialties when operating refineries for minimum production of residual fuel oil.

It is recognized that the phrase "minimum production of fuel oil" allows considerable latitude in view of the different types of refinery equipment in use. The term "minimum" as used here is intended to mean the weighted average of individual minima of each refinery. For example, refiners with sufficient catalytic cracking equipment may have minimum residual yields of 12 to 14 per cent on crude charged when producing their requirements of gasoline, kerosine, and distillates from light (32° to 38° A.P.I. gravity) crudes. Other refiners may have no cracking equipment of any kind. Their minimum residual fuel oil yields may be between 30 and 50 per cent, or even higher, if heavy crudes are used. Even fully equipped refiners operating on heavy crudes may not be able to lower their yields below 30 per cent. This is especially noticeable in California, where, in spite of a large amount of catalytic cracking, the average yields exceed 40 per cent because of the preponderance of heavy crudes used.

On an average, the residual fuel oil yield for the country has been about 26 per cent in recent months, which normally would drop to an average of 25 per cent for the year 1946 as a result of diversion of residual fuel oil to asphalt and road oils in the summer. However, even higher average yields than 26 per cent are expected because of the need for blending distillate with residual to meet the high demands for the latter product.

It is reasonable to expect that each individual refiner will continue to minimize his yield of residual fuel oil unless paid the cost of blending distillate with residual. In almost all cases in the United States, the cost of crude oil to the refiner is higher than the realization for residual fuel oil. Therefore, production of residual above the minimum possible with the crudes and equipment available usually involves an out-of-pocket loss to the refiner. Adequate proof of this economic reasoning has been evident since V-J day, when, despite the maximum imports of residual fuel oil and heavy crudes, stocks of residual fell below minimum working levels at the end of January and requirements could not be met in full. Full requirements during the peak consumption period were supplied eventually by blending distillates with by-product residual. This was made possibly economically by the Navy, which paid the added costs involved. The argument might be made that an increase in the price levels for residual fuel would change this situation and increase domestic production of this product. With the exception of artificial gravity-price scales or special prices to individual consumers, such as the Navy, which can be justified only in emergencies, it does not appear likely that the probable future price changes will alter the situation, having in mind that coal parity will always place a ceiling on prices for residual fuel oil. Small increases in prices of residual fuel up to new, higher coal parities may be expected in the future. It is more than probable, however, that domestic crude oil prices will rise at least as much as the maximum rise in residual fuel prices, reflecting higher costs of crude oil production, particularly higher replacement costs. This means that the refiner would continue to suffer a substantial out-of-pocket loss if he increased residual yields above minimum. Alternatively, if producers of domestic crude oil should desire to secure all of the possible crude oil outlet represented by the deficit between residual fuel oil supply and demand, any crude oil price rise would be precluded and even some decrease might be necessary in line with the lower average value of the products refined. In view of the constantly increasing costs of finding and producing crude oil, it does not seem reasonable to expect the domestic producer voluntarily to hold his realizations at a level that many claim would result in a loss merely to sell more crude.

The producers have been very specific and articulate on this subject for several years.

PROBABLE DOMESTIC PICTURE FOR NEXT TEN YEARS

Over the next 10 years, it appears likely that the United States will continue in its present role as exporter of overhead products and importer of residual fuel and crude, particularly special and heavy crudes. It is expected that the present high export requirements will continue for the next 3 to 5 years and then decline gradually during the next 5 years.

Inasmuch as Eastern Hemisphere demands are projected to increase about 685,000 bbl. per day (excluding Russia) and Western Hemisphere demands outside of the U.S. about 225,000 bbl. per day, foreign crude oil production and refining operations are expected to continue at maximum capacity, with foreign refining capacity increasing as new refinery equipment becomes available. Despite this anticipated expansion, it appears doubtful whether exports from the U.S. can be reduced to a minimum level of, say, 100,000 bbl. per day, representing only specialty products and tributary exports, within the next 10 years. To reduce U.S. exports to this extent it would be necessary to increase crude production and refining in areas outside of the U.S. by 1,900,000 bbl. per day during this period. Such an increase would require several billion dollars of capital expenditure, as well as a very considerable increase in technically trained employees, who are not available at present. While it is not inconceivable that this could be accomplished, it would seem more probable that the United States will continue to be an exporter of light products—gasoline, kerosine, distillates and lubricating oils—and will continue to import residual fuel oil and crude oils to the extent necessary to utilize existing refining capacity.

Tables 1 and 2 compare the latest estimates for 1946 with a possible situation in 1950 and 1956 or thereabouts.

It is interesting to note that projections by years indicate that the 1950 level of total demand will be reached in 1948 and perhaps exceeded slightly in 1949.

There are, of course, many speculative elements in the forward picture. For example, it has been assumed that a large amount of catalytic cracking equipment would be installed to balance the increased requirements for gasoline and distillates, thereby reducing yields of residual fuel oil from 26.7 to 16 per cent after 10 years. However, the Hydrocarbon Synthesis Process may prove to be more economical than catalytic cracking for the manufacture of gasoline, thus making less desirable the projected expansion of catalytic cracking facilities. The chief result of a lower rate of construction of catalytic cracking installations would be a higher average yield of residual fuel oil, accompanied by a reduction in imports.

Domestic crude production is difficult to predict. In 1947 and for several years it will probably be necessary to produce above maximum efficient rates, which are presently estimated to be about 4,500,000 bbl. per day. While it is expected that new findings will be sufficient to sustain this maximum efficient rate for 5 years, if

TABLE 1.—*Estimated Requirements, Thousand Barrels Daily*

Product	Year 1946			Year 1950			Year 1956		
	Dom.[a]	Export	Total	Dom.[a]	Export	Total	Dom.	Export	Total
Gasoline	1,917	141	2,058	2,358	68	2,426	2,550	50	2,600
Kerosine	208	25	233	236	14	250	240	10	250
Distillates	613	108	721	842	68	910	910	40	950
Residual	1,351	34	1,385	1,154	4	1,158	1,200		1,200
Other products and losses	642	40	682	757	28	785	790	10	800
Total products	4,731	348	5,079	5,347	182	5,529	5,690	110	5,800
Crude oil	38	89	127	41	80	121	40	60	100
Total crude and products	4,769	437	5,206	5,388	262	5,650	5,730	170	5,900

[a] Domestic requirements include all domestic purchases of the U.S. Armed Forces whether for on-shore or off-shore consumption. Military drafts on owned stocks are not included in the requirement figures.

TABLE 2.—*Estimated Refining Operations*

	Year 1946		Year 1950		Year 1956	
Crude runs to stills, bbl.	4,597		4,980		4,760	
	M Bbl. per Day	Per Cent	M Bbl. per Day	Per Cent	M Bbl. per Day	Per Cent
Product yields:						
Gasoline	1,810	39.4	2,138	43.0	2,130	44.8
Kerosine	238	5.2	249	5.0	250	5.2
Distillates	714	15.5	886	17.8	920	19.3
Residual	1,230	26.7	996	20.0	760	16.0
Other products and losses	605	13.2	711	14.2	700	14.7
Total	4,597	100.0	4,980	100.0	4,760	100.0
Total supply:						
Domestic crude production		4,528[a]		4,760		4,200[b]
Domestic natural gasoline, condensates, etc.		328		361		400
Hydrocarbon Synthesis				10		200
Crude imports		255		366		680
Residual imports[c]		110		136		400
Miscellaneous imports[c]		15		17		20
Total		5,236[a]		5,650		5,900

[a] Includes 30,000 bbl. per day for stock increase.
[b] Estimated maximum efficient producing rate.
[c] Includes bonded imports for bunkering vessels in foreign trade.

crude were produced at M.E.R., the probable need for production above this rate would, no doubt, reduce both the future M.E.R. and maximum sustained productive rate. It is for this reason that a rate of only 4,200,000 is shown for 1956. If findings are better than generally expected, it is quite possible that crude production would be higher in 1956. In this case the production from Hydrocarbon Synthesis would probably be lower, the refinery yields of residual higher and residual imports correspondingly lower. It should be realized that the domestic production indicated above represents about 17 billion barrels. Few, if any, qualified students of the problem would hazard a guess that any more crude than this amount can be found in the United States within the next 10 years.

The foregoing picture is not, therefore, a definite prediction, but more a basis for intelligent speculation.

PROBABLE DOMESTIC PICTURE IN 20 YEARS

It appears reasonable to believe at the present time that the increasing domestic requirements between 10 and 20 years from now will be met by a combination of the following methods:

1. Crude, natural gasoline and condensate production at maximum efficient rates.
2. Further expansion of the Hydrocarbon Synthesis Process.
3. Further reduction of residual fuel oil yields to produce more light products from crude oil with increased residual imports to balance.
4. Increased crude oil imports.

The domestic picture, therefore, is one of a healthy situation for the crude producer, who most probably will have an outlet for all the crude he can find and produce efficiently. Realizations should rise to offset his probable rising costs, principally as a result of new refining techniques, which yield higher quantities of the more valuable products. The refining industry will soon be short of sufficient modern equipment and considerable new construction may be anticipated. At the same time the need and economic justification for new processes, such as Hydrocarbon Synthesis, are becoming quite apparent, and this offers a fertile field for expansion.

PROBABLE FOREIGN PICTURE IN NEXT 10 TO 20 YEARS

As mentioned before, Eastern Hemisphere requirements are projected to increase at a rapid rate. It may, therefore, be expected that refinery construction will be undertaken on a large scale in this area. Concurrently large pipe-line installations will become economically desirable, and as these facilities become available crude oil production will be immediately and easily increased to meet the demand. The increased production is expected in the Persian Gulf and Iraq fields, with substantial increases also in the East Indies. Ample proved reserves are available in these areas to sustain the production that might be required in the next 10 to 20 years.

The principal refinery construction will take place, no doubt, in the Mediterranean, Persian Gulf, East Indies and Europe. The rate at which this can be accomplished will affect the future exports from the United States, but sufficient construction merely to meet increasing demands in the area will be a sizable job.

In the Western Hemisphere outside of the United States continued activity may be expected in oil-finding operations, in order to discover new reserves to support present production, as well as to provide for meeting increasing requirements, both outside of the U.S. and for importation into the U.S. to balance domestic deficits. Some refinery expansion may be anticipated, but not to the same extent as in the Eastern Hemisphere. If the net increased requirements in this area are principally residual fuel, as has been projected, the refinery installations required will, in fact, be relatively minor. So far the most prolific discoveries of crude oil in Latin America have been heavy crude oils that are particularly well suited to residual production. In some areas, such as Western Canada, where gas supplies are ample, the future use of the Hydrocarbon Synthesis Process may prove more economic than the very costly and relatively unproductive search for new crude oil reserves in that area. The possibility of using this process with coal as a raw material in areas where coal is abundant and crude oil scarce also appears promising in the future.

The requirement trends are upward everywhere. The supply of these requirements will involve shifts in major producing areas with the principal developments in the Middle East. Where crude oil is short and finding costs too high, alternate means are available for meeting the demands. The petroleum industry has never known any insurmountable problems and there is nothing in the forward picture to indicate that any will be met—at least in the next 20 years.

Review of Refinery Engineering

BY WALTER MILLER

A SURPRISING development during the year was the continued high demand for petroleum products and the high level of crude oil charges to the stills. Generally speaking, the petroleum industry during 1946 succeeded in producing a greater quantity of crude oil and petroleum products than in any of the war years, and considerably exceeded the production of any prewar year. Daily crude still charges averaged between 4,700,000 and 4,800,000 bbl per day for 1946 and about equaled the 1945 record, although most pessimistic 1945 guesses, predictions, or fears ranged, for 1946, from only 3,900,000 to 4,400,000 bbl per day. In spite of the high crude charge to the stills, total stock of crude oil was higher at the end of the year by some 7,000,000 to 8,000,000 bbl.

A similar story holds regarding stocks of the principal refined products. Gasoline on hand at year's end was two to three million barrels lower, and was considered low for the expected demand during the coming high consuming season, while stocks of light and heavy fuel oils, although some higher than a year previous, hardly reached a comfortable level.

The trend in gasoline of high octane number, which has resulted in a marked rise in the antiknock quality by the end of 1945 (five or six numbers higher than during the war and one number higher than the prewar quality of civilian motor gasoline of 1941) was abruptly arrested by an acute shortage of metallic lead for manufacturing tetraethyl lead. Government action in the form of lead price control, rationing, and the setting of octane ceiling specifications to conform to the reduced ethyl lead compound available were enforced until abrogated at the end of the year. It will be interesting to see how rapidly the octane levels will resume the rising trend, as more metallic lead slowly becomes available for making greater quantities of ethyl lead compound.

As octane quality rises over present levels the disadvantage of the refiner without catalytic cracking equipment will increase. Gasoline made by catalytic cracking, without addition of ethyl lead, approximates 77 octane by the official ASTM Motor Method test, compared with 66 for gasoline generally similar in volatility made by the older thermal cracking operation. Catalytic gasoline shows an even greater improvement in the Research octane number, the comparison being roughly 86 Research versus 71 Research octane for the thermal cracked product. This higher differential in Research octane is credited by many, although not universally so, as contributing to better road performance, and consequently resulting in a more desirable product marketwise.

In some parts of the country a premium of roughly one fourth cent per gallon is now being paid for gasoline with higher Research octane made possible by including catalytic cracked product in the final blends. If such price differentials in favor of catalytic gaso-

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† Vice-President, Continental Oil Co., Ponca City, Oklahoma. Chairman, Committee on Refinery Engineering, Petroleum Division, A.I.M.E.

line become general, it will add further to the disadvantage of the noncatalytic refiner.

The economic problem of installing catalytic cracking in refineries charging less than say 7500 bbl of crude oil per day has not been satisfactorily solved. The investment cost per barrel of capacity rises rapidly with reduction in size, and the same applies to operating costs. Therefore unless special considerations peculiar to a specific refinery situation reduce installation costs, by permitting the use of applicable existing equipment not otherwise needed, the above figures seem to be the approximate dividing line at present between economic and noneconomic planning.

Although much has been accomplished in improving design and simplifying operations leading to lower capital investment and better operating costs than was first thought necessary, and although in some cases the urgency of the need for high-octane gasoline will to some extent override economics, the rule of higher costs for smaller installations will have its limiting effect.

Two of the smaller types of units are under construction and should be completed before the middle of 1947, and much information for future small plant development is looked for from their operation.

Seven of the wartime Government-built catalytic cracking units are in operation. Two of these have been purchased by the respective refiners, and five are being operated under rental arrangements with slow negotiations going on looking to possible purchase by the refiners. Seven of the total of fourteen are idle, and four or five of these are so situated that they hold little prospect of ever being utilized.

Since V-J Day some ten additional large-size catalytic installations have been started in the United States, with two or three of them completed and in operation, the rest in various stages of construction.

Many additional catalytic cracking projects and situations are under study and in prospect. Impending higher octane standards will continue to make that one of the most important problems confronting the refiner not yet so equipped. As the situation clarifies and construction materials become increasingly available new installations will rapidly be initiated.

A postwar note on 100-octane aviation gasoline is to the effect that the 30,000,000 to 40,000,000 bbl on hand at the close of fighting have been almost exhausted, and the Government will in a few months resume buying for current requirements.

Lubricating Oil

It will be remembered that at a number of times during the war, fears arose as to the ability of the refiners to make all the lubricating oils required. A number of projects for increasing the manufacturing capacity were proposed and engineered, but not authorized by Washington for installation during the war. Experience indicated that sufficient lubricants would be made by refiners and therefore the expenditure of large quantities of construction materials needed elsewhere could be avoided. Four or five of these delayed projects were well along and should be among the first new installations to get into operation.

A recent survey indicated that some twenty projects, including the ones mentioned above, and many including wax manufacturing equipment, were on the active list for the United States. Several of these plants have been contracted for, and the rest are in various stages of planning, estimating or contracting negotiations. Most of them are sure of ultimately being carried through to completion over the next two years or so.

Many of the installations will be for new capacity and all for solvent-treating processing, but a substantial proportion is to be replacement capacity to supplant existing old acid-type plants reaching toward obsolescence, as well as two or three early-type solvent-treating plants no longer competitive. Although the figures given here are only approximate, the indications given by the private survey referred to are that a total of 30,000 bbl per day of new capacity is planned, but 18,100 bbl will be to supplant a similar capacity of the older plants to be discontinued as the new solvent-treating replacement installations are put into service. A net increase of approximately ten per cent in total manufacturing capacity will be added to the present average 120,000 bbl per day U.S. capacity. An appreciable rise in quality level will result, and like the refiners without catalytic cracking, the plants without solvent treating and the resultant higher lubricating quality will be at an increasingly serious disadvantage.

Some uses for the older-type oils will continue, but solvent-treated quality will generally be used in preference for all internal-combustion-motor operations, and application to other services is increasing steadily. The old acid-treated lubricating oils are fast receding from the picture.

Application is broadening of the principle of adding special ingredients in minute proportions to oils for improving lubrication effectiveness. Although of long standing, the practice received a tremendous impetus during the war as the industry was called upon to solve new lubricating problems occasioned by innumerable new and more severe requirements incidental both to manufacturing war machinery and equipment, and service under combat conditions. Much of the wartime development was secret until the war's end, since when the new ingredients and additives have been available for industry-wide use. The ever-continuing search for newer and better additives and ingredients resulted in some recent announcements which are rapidly becoming incorporated in practice.

Research in the petroleum refining art reached out on a widening front through the year as the limitations imposed by previous war requirements were relaxed. Many plans for new scientific laboratories and expansions of existing research installations have been announced on a scale which will provide equipment and space many times that of today. Many new oil companies are joining in the search for new processes, new products, and new knowledge. The large number of research problems successfully worked out during the war years, both as individual programs and the combined efforts of many individuals and companies, constitute a background and starting point for wider and newer efforts. The good augury for greater success in more strongly and integrally welding petroleum and its practically unlimited chemical source materials with the great chemical industry is especially attractive to energetic seekers for greater future progress and profits.

Oil from Other Sources

The Bureau of Mines is developing the technique for manufacture of liquid petroleums from other source materials against the future days when the crude oil supply falls short. Coal, oil shale, natural gas, and other materials are being investigated as sources; fortunately an immediate answer to the problem is not imperative.

Liquid petroleums from natural gas by the Fischer-Tropsch process should soon have the first full-sized demonstration of its practicability under American conditions. The first commercial installation is being erected near Brownsville, Texas, and will probably be ready for operation early in 1948. It will process approximately 70,000,000 cu ft of natural gas a day and produce roughly 5000 bbl of gasoline plus 2000 bbl of other liquid products available in part as Diesel engine fuel and in part raw material for the manufacture of chemicals. A $20,000,000 to $22,500,000 investment will probably be required.

The second installation is planned for erection at the huge Hugoton gas field in southwestern Kansas. Announcement by the Stanolind Oil and Gas Co., of Tulsa, is to the effect that approximately 100,000,000 cu ft of dry gas will be processed daily. With the later start and somewhat larger charging capacity, it will probably not be ready for operation until late in 1948 or early 1949.

Estimates of total gas reserves in the United States have reached considerably higher figures than the 140 trillion cubic feet quoted at the beginning of 1946, figures of 173 trillion cubic feet estimated as proved and an ultimate potential of 200 trillion cubic feet or more having been mentioned within recent months. Not all of these reserves, however, will be available for Fischer-Tropsch installations, because of smallness of many of the pools and poor location and accessibility. Any figure would be mostly guess, and one might judge that only twenty five to forty per cent of the total could be utilized ultimately. But if that much is available and usable for making Fischer-Tropsch gasoline it will create a tremendous increased reserve in available motor fuel over the years and push back into the future for many long years the necessity for making gasoline from coal, likely at much higher cost.

The progress being made in this field is being observed closely by all the larger integrated oil companies. A few have evidenced publicly their interest and possible future participation. For the long pull the commercial and practical results of the two large installations now under way will be looked to in arriving at future decisions.

Synthetic rubber production is no longer a petroleum refining industry problem. Rather it is a question of national and international economics as to the relative extent on which each of the ample potential sources of the synthetic and natural products will be drawn.

The world-wide crude oil supply and petroleum refining situations will be profoundly affected in ensuing years as a result of the recently announced move for the Standard Oil Co. of (New Jersey) and Socony-Vacuum Oil Co. to acquire substantial shares in the ownership and operation of the vast Saudi Arabia interests of the Arabian American Oil Co., now jointly owned by Standard Oil Co. of California and The Texas Co.

A highly augmented rate of crude oil production in Saudi Arabia, a large pipe line to the Mediterranean, important increases in refining capacity in European and other foreign countries, a lessening drain for export of crude oil from North and South America, a decrease of exportation of petroleum products generally from the United States, as well as lessened dependence of outsiders on the United States refineries for lubricating oils—all these possibilities occur as one speculates on the future.

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